INNOVATIVE CLEAN COAL TECHNOLOGY

Plant Crist SCR Project
SCR Pilot-Plant

Design Bases

Volume 1

Project No.
DE-FC22-90PC89652

DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY FOR THE CONTROL OF NITROGEN OXIDE (Nox) EMISSIONS FROM HIGH-SULFUR, COAL-FIRED BOILERS

PREPARED FOR
U.S. DEPARTMENT OF ENERGY
PITTSBURGH, PENNSYLVANIA

JUNE 1991

SCR

INNOVATIVE CLEAN COAL TECHNOLOGY
PLANT CRIST SCR PROJECT
SCR PILOT PLANT

DESIGN BASES
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1.0 INTRODUCTION

This project is being conducted as part of the U.S. Department of Energy (DOE) Innovative Clean Coal Technology Program. The project is a demonstration and evaluation of commercially available selective catalytic reduction (SCR) catalysts from United States, Japanese, and European catalyst suppliers.

1.1 PROJECT DESCRIPTION AND OBJECTIVES

SCR is a post-combustion nitrogen oxide (NOx) control technology that involves injecting ammonia into the flue gas generated from coal combustion in an electric utility boiler. The flue gas containing ammonia is then passed through a reactor that contains a specialized catalyst. In the presence of the catalyst, the ammonia reacts with NOx and is converted to nitrogen and water vapor.

Although SCR is widely practiced in Japan and Europe, there are numerous technical uncertainties associated with applying SCR to U.S. coals. These uncertainties include:

1. Potential catalyst deactivation due to poisoning by trace metal species present in U. S. coals that are not present in other fuels.

2. Performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of SO_2 and SO_3.

3. Performance of a wide variety of SCR catalyst compositions, geometries and methods of manufacture under these new operating conditions.

These uncertainties will be explored by constructing a series of small-scale SCR reactors and simultaneously exposing different SCR catalysts to flue gas from the combustion of high sulfur U.S. coal.

The project will be conducted at Gulf Power Company's Plant Crist Unit 5, a commercially operating 75 MW unit, located in Pensacola, Florida, on U.S. coals with a sulfur content near 3.0 percent. Unit 5 is a tangentially-fired, dry bottom boiler, with hot and cold side electrostatic precipitators (ESPs) for particulate control. The SCR process to be used in this demonstration will be designed to treat a slip-stream of flue gas and will feature multiple reactors installed in parallel. With all reactors in operation, the maximum amount of combustion flue gas that can be treated is 17,400 standard cubic feet per minute (scfm) which is roughly equivalent to 8.7 MWe.

The proposed Southern Company Services, Inc. (SCS) facility is a slip-stream SCR test facility consisting of three 2.5 MWe, 5000-scfm and six 0.20 MWe, 400-scfm SCR reactors that will operate in parallel for side-by-side comparisons of commercially available SCR catalyst technologies obtained from vendors throughout the world. The large, 2.5 MWe SCR reactors will contain commercially available SCR catalysts and will be coupled with pilot-scale air preheaters to evaluate the long-term effects of SCR reaction chemistry on air preheater deposit formation and the deposits' effects on air preheater thermal performance. The small reactors will be used to test additional commercially available catalysts. All but one of the SCR reactors will treat high dust flue gas from a slip-stream taken upstream of the Unit 5 hot-side ESP. One of the small SCR reactors will operate with low dust flue gas from a slip-stream taken downstream of the Unit's hot-side ESP. This demonstration facility size will be adequate to develop performance data for evaluating SCR capabilities and costs that are applicable for boilers using high-sulfur U.S. coals.

This project is proposed for construction between Units 5 and 6 at Plant Crist, and the project will be conducted in the following three work phases during two budget periods:

<u>Work Phases</u>	<u>Budget Period</u>
Phase I - Permitting and Preliminary Engineering	I
Phase II - Detailed Engineering, Construction, and Startup	I
Phase III - Operation, Testing, and Disposition	II

Table 1.1-1 presents the work breakdown structure for the first two phases of the project. Figure 1.1-1 presents the most recent schedule for Phases I and II. The pilot plant is now scheduled to begin startup on November 1, 1992. Phase II should be concluded after about a three-month startup period, and testing is scheduled to commence in late January 1993.

Table 1.1-1

Work Breakdown Structure

Phase I - Permitting, Environmental Monitoring Plan, and Preliminary Engineering

Task 1.1.1 - Prototype Plant Permitting Activities
Task 1.1.2 - Environmental Monitoring Program Development
Task 1.1.3 - Preliminary Engineering
Task 1.1.4 - Engineering and Construction Contracts Scope Development
Task 1.1.5 - Project Management and Reporting

Phase II - Detail Design Engineering Construction

Task 1.2.1 - Detailed Design Engineering
Task 1.2.2 - Construction
Task 1.2.3 - Operation Staff Training
Task 1.2.4 - Planning for Detailed Testing
Task 1.2.5 - Start-Up/Shakedown
Task 1.2.6 - Project Management and Reporting

2.0 DESIGN BASES

This section includes some of the major design bases and assumptions used in the engineering design for this SCR pilot plant facility. Site characteristics such as coal analyses, ash analyses, boiler unit characteristics, and flue gas composition are given. Information on the SCR catalysts are included. Drawings of the layout of the pilot plant are shown, as well as process flow diagram and material and energy balances. The philosophy for pilot plant operations is also discussed.

2.1 SITE CHARACTERISTICS

Plant Crist consists of 7 fossil generating units that are designed to utilize a variety of fuels. Units 1, 2, and 3 are natural gas and oil-fired, and consequently do not have a high utilization factor. The remaining units, 4 through 7, are coal-fired. A brief description of the Crist units and site specific design conditions are shown in Tables 2.1-1 and 2.1-2, respectively. These units are arranged as shown in the layout of the Plant Crist site in Figure 2.1-1.

The prototype SCR facility will be built in and around the ductwork on Unit 5, with the ability to extract flue gas from Unit 5 either upstream of the hot-side ESP, high dust, or downstream of the hot-side ESP, low dust. Eight of the SCR reactors will operate with high dust levels while one small reactor will operate with the low dust loading. A photograph of the SCR pilot-plant location is shown in Figure 2.1-2.

Originally, the SCR pilot facility was to be able to operate on flue gas slip-streams from either of Crist Units 5 or 6. However, it has since been decided to eliminate Unit 6, a 320-MW, wall-fired, dry bottom boiler, from the project because the existing flue gas conditions on Unit 6 make it impossible to extract a consistent, representative flue gas slip-stream for use in the pilot SCR reactors. Test data from SRI's duct characterization tests and review of these data by DynaGen revealed wide variations in flue gas velocities and flow directions as well as particulate mass loadings at the only available location on Unit 6 where a slip-stream can be extracted. In contrast, the data show ideal conditions for slip-stream extraction from Unit 5. Retaining Unit 6 in the project would jeopardize the technical quality of the data to be produced in the pilot SCR reactors.

Eliminating Unit 6 does not negatively affect the technical value of this project. Substantial data will still be produced on the influence of high-sulfur U.S. coal on commercially available SCR catalyst performance and life. The results of SRI's test data show that there are sufficient variations

Table 2.1-1

Characteristics of Plant Crist Units 1 - 7

Unit Number	1	2	3	4	5	6	7
Size, MW	22.5	22.5	30	75	75	320	500
Boiler Manufacturer	Riley	Riley	Riley	CE	CE	FW	FW
Boiler Capacity, klbs/hr	230	230	320	582	582	2,337	3,626
Steam Pressure, psig	850	850	850	1800	1800	2400	2400
Steam Temperature, °F	900	900	900	1000/ 1000[a]	1000/ 1000	1000/ 1000	1000/ 1000
Start-up Month	6/45	6/49	9/52	6/59	4/61	5/70	5/73
Fuels Capable	Gas/ Oil	Gas/ Oil	Gas/ Oil	Gas/ Coal	Gas/ Coal	Gas/ Coal	Coal
Cooling Source[b]	OT/H	OT/H	OT/H	OT/H	OT/H	CT/CL	TC/CL

[a] Superheat/Reheat Temperature
[b] OT/H = Once Through cooling with helper tower during summer months.
CT/CL = Cooling Tower with closed loop.

Table 2.1-2

Site Specific Design Conditions

Elevation above sea level: 0' - 0"

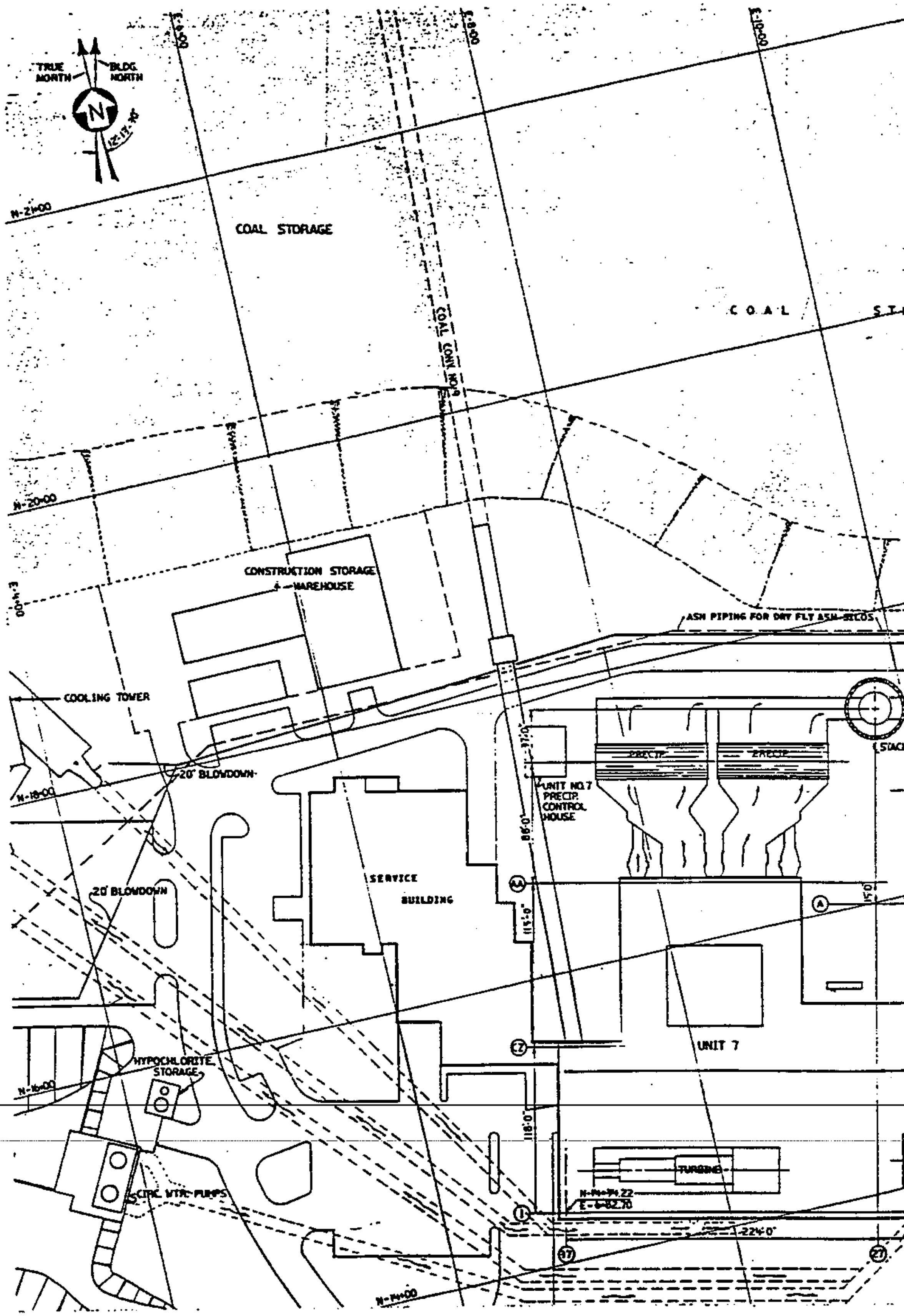
Grade datum elevation: 90' - 0"

Design ambient temperature: Summer - 100°F, Winter - 32°F

Design ambient pressure - 29.92" Hg

Design relative humidity - 95%

Seismic load zone - VBC Zone 0



TRUE NORTH
BLDG. NORTH
N
N-21+00
COAL STORAGE
C O A L
COAL CONV NO. 6
N-20+00
CONSTRUCTION STORAGE & WAREHOUSE
ASH PIPING FOR DRY FLY ASH SILOS
COOLING TOWER
20" BLOWDOWN
N-18+00
UNIT NO.7 PRECIP. CONTROL HOUSE
PRECIP.
PRECIP.
STACK
SERVICE BUILDING
20 BLOWDOWN
UNIT 7
HYPOCHLORITE STORAGE
N-16+00
CIRC. WTR. PUMPS
TURBINE
N-14+14.22
E-6+82.70
224'-0"
N-14+00

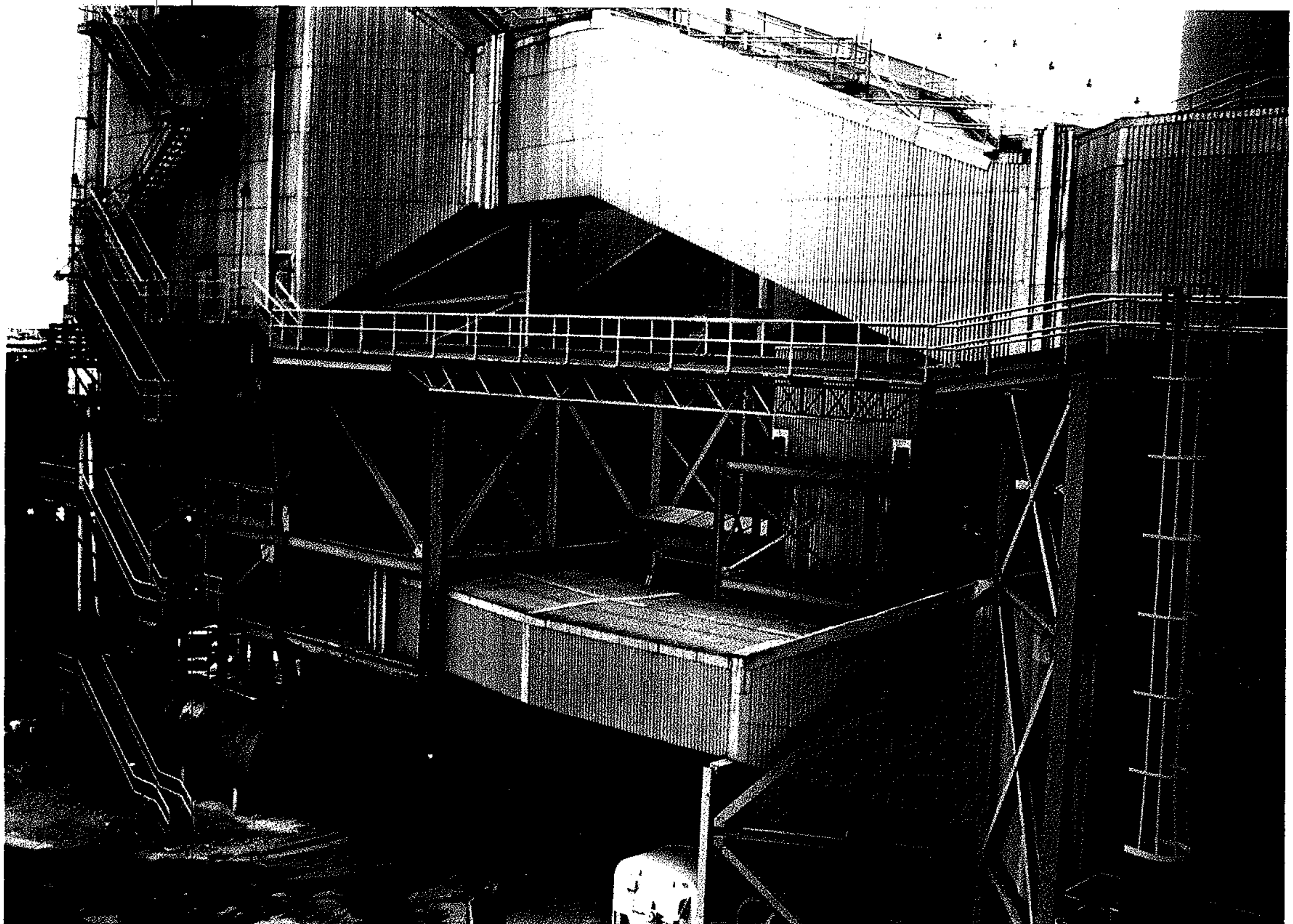


Figure 2.1-2. Photograph of the SCR pilot-plant location.

in NOx levels from Unit 5 that statistical analyses of the pilot plant data will allow SCR performance as a function of inlet NOx to be determined from the data that will be developed as part of this project. This type of analysis will provide the information that was sought by including Unit 6 in the original proposal since Unit 6 NOx emissions are typically higher than those of Unit 5. More details to the technical rationale for this decision are provided in EXHIBIT 2.1-A.

2.1.1 Coal Analyses

The following coal analyses should be used as a design basis for the SCR project. These analyses do not represent any single determination of a particular sample. Rather they are based upon selecting reasonable values that represent the midpoint of a range of analyses collected over the last few years.

Design Fuel Analyses:

Carbon, %	67.80
Hydrogen, %	4.60
Sulfur, %	2.90
Nitrogen, %	1.40
Chlorine, %	0.25
Ash, %	9.50
Moisture, %	7.90
Oxygen, % (by diff.)	5.65
Heating Value, Btu/lb	12,200

2.1.2 Ash Analyses

The following flyash analyses should be used as a design basis for the SCR project. These analyses do not represent any single determination of a particular sample. Rather they are based upon selecting reasonable values that represent the midpoint of a range of analyses collected over the last few years.

Design Flyash Composition:

SiO_2, %	50.4
Al_2O_3, %	19.9
Fe_2O_3, %	18.1
TiO_2, %	1.0
CaO, %	4.2
MgO, %	1.0
K_2O, %	2.6
Na_2O, %	0.7
SO_3, %	1.4
P_2O_5, %	0.3
LOI*, %	6.5

*LOI = Loss on Ignition and typically represents unburned carbon.

2.1.3 Flue Gas Composition

The following flue gas composition should be used as a design basis for the SCR pilot plant.

Components	Flue Gas Composition (vol%)	Flue Gas Compositon (wt%)
CO_2	13.854	20.567
O_2	2.967	3.202
N_2	73.283	69.239
SO_2	0.222	0.480
SO_3	0.0020	0.0054
NO	0.03798	0.0384
NO_2	0.00200	0.0031
HCl	0.01038	0.028
H_2O	9.621	5.848
Ash	---	0.604
Total	100.000	100.000

The flue gas composition was calculated from combustion calculations using the design coal analysis from Section 2.1.1. The material balance of the pilot plant is based on the combustion calculation. Furthermore, trial and error combustion calculations were performed to close the material balance to match the following field measurements:

O_2	- 3%
SO_3	- 20 ppm
NOx	- 400 ppm
High Dust	- 8000 mg/Nm^3
Low Dust	- 50 mg/Nm^3

Field measurement results from Unit 5 for duct static pressures and flyash particle size distributions are shown in EXHIBIT 2.1-B and 2.1-C, respectively.

EXHIBIT 2.1-A

TECHNICAL RATIONALE FOR ELIMINATION OF UNIT 6

ATTACHMENT 1

Technical Rationale for Elimination of Unit 6

Unit 6 will be dropped from the project for the following reasons:

a. Detailed technical discussions have been held with catalyst suppliers during Phase 1 in order to finalize SCR pilot reactor design criteria. These discussions have revealed substantial differences in SCR reactor designs that would be used if the higher inlet NOx levels found by SRI from Unit 6 testing (on 7/28/90 - 8/7/90) were to be included in the design basis. Moreover, it is already known that a reactor/catalyst system that is designed for Unit 5 inlet NOx levels will not perform as well if Unit 6 flue gas were to be introduced (not enough catalyst volume, consequently space velocities would be too high).

b. Recent data from Unit 5 indicate that inlet NOx levels could vary by as much as 150 ppm (i.e. between 250 and 400 ppm depending upon unit load and excess O_2), which is sufficient to evaluate the response of SCR to changes in inlet NOx. This evaluation can be accomplished by recording inlet NOx level as part of the statistical data analyses and analyzing deNOx performance as a function of inlet NOx.

c. By maintaining the original design concept of periodically ducting Unit 6 flue gas into reactors that are designed for (and primarily operated on) Unit 5 flue gas, the possibility exists of introducing higher levels of trace metal catalyst poisons from Unit 6 flue gas onto the catalyst. Subsequent catalyst composition analyses will be made more difficult since the flue gas source over the catalyst would have varied between two different sources and it will not be possible to determine the origin of trace metal contamination.

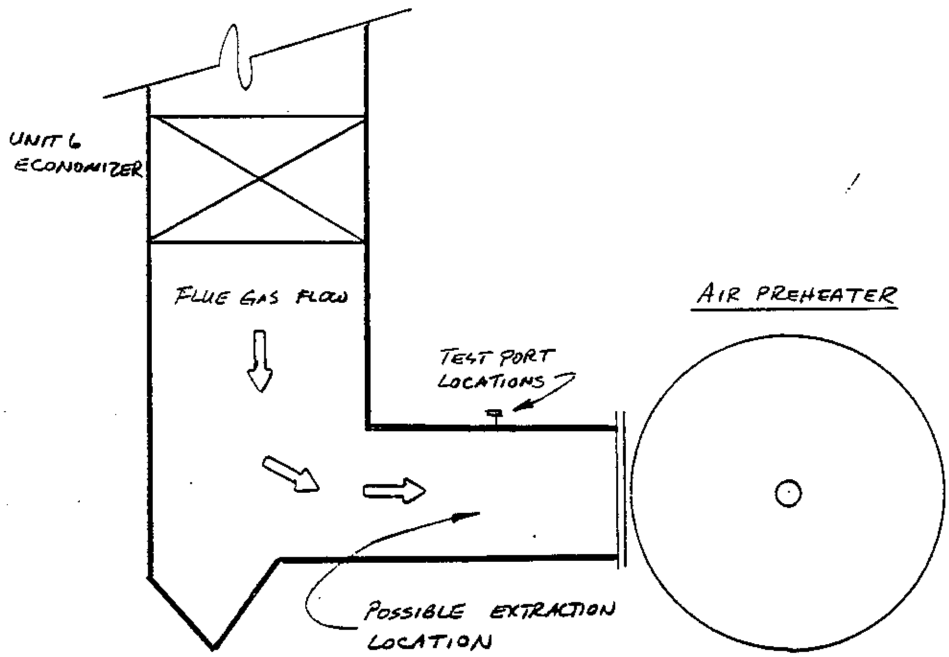
d. Unit 6 is an uncontrolled, "first generation" wall-fired burner equipped boiler. Consequently, its flame zone combustion conditions are typical of high-combustion intensity boilers. The flue gas generated from such a combustion zone will likely be different than that of the type generated by the mixing controlled and O_2-diffusion controlled tangentially-fired Unit 5 boiler. Moreover, as a practical matter it is unlikely that SCR would ever be installed on an uncontrolled wall-fired boiler without first retrofitting low-NOx burners. LNB retrofits would be more likely to produce a mixing and O_2-diffusion controlled flame (i.e. trending toward a t-fired mode), which validates the use of Unit 5 as a source of flue gas.

e. Finally, detailed site inspections and data collected in the field by SRI and analyzed by DynaGen, Inc. confirm that extracting a representative slipstream of flue gas from Unit 6 ahead of the air preheater will be a formidable, if not impossible, task. The flue gas velocities and particulate mass loadings vary dramatically over the duct area available for an extraction scoop location due, in large part to the host boiler duct configuration (see Figures 1 and 2). It is highly unlikely that a representative sample of flue gas could be consistently extracted from Unit 6 for use in the pilot plant.

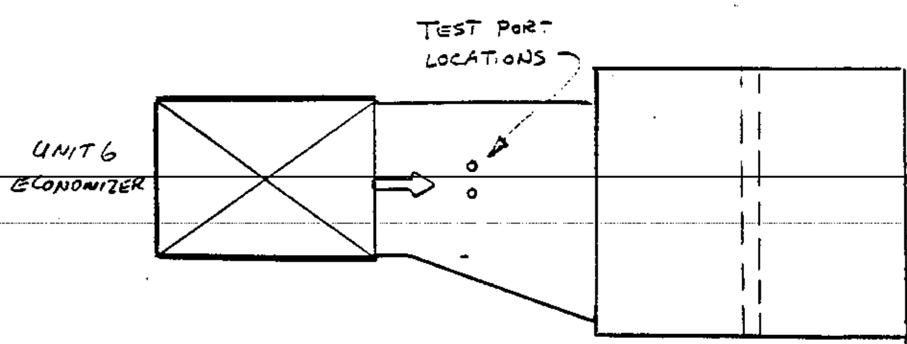
For the reasons outlined above, Unit 6 has been dropped from the project.

FIGURE 1

SKETCH OF UNIT 6 FLOW CONFIGURATIONS



ELEVATION VIEW



PLAN VIEW

FIGURE 2

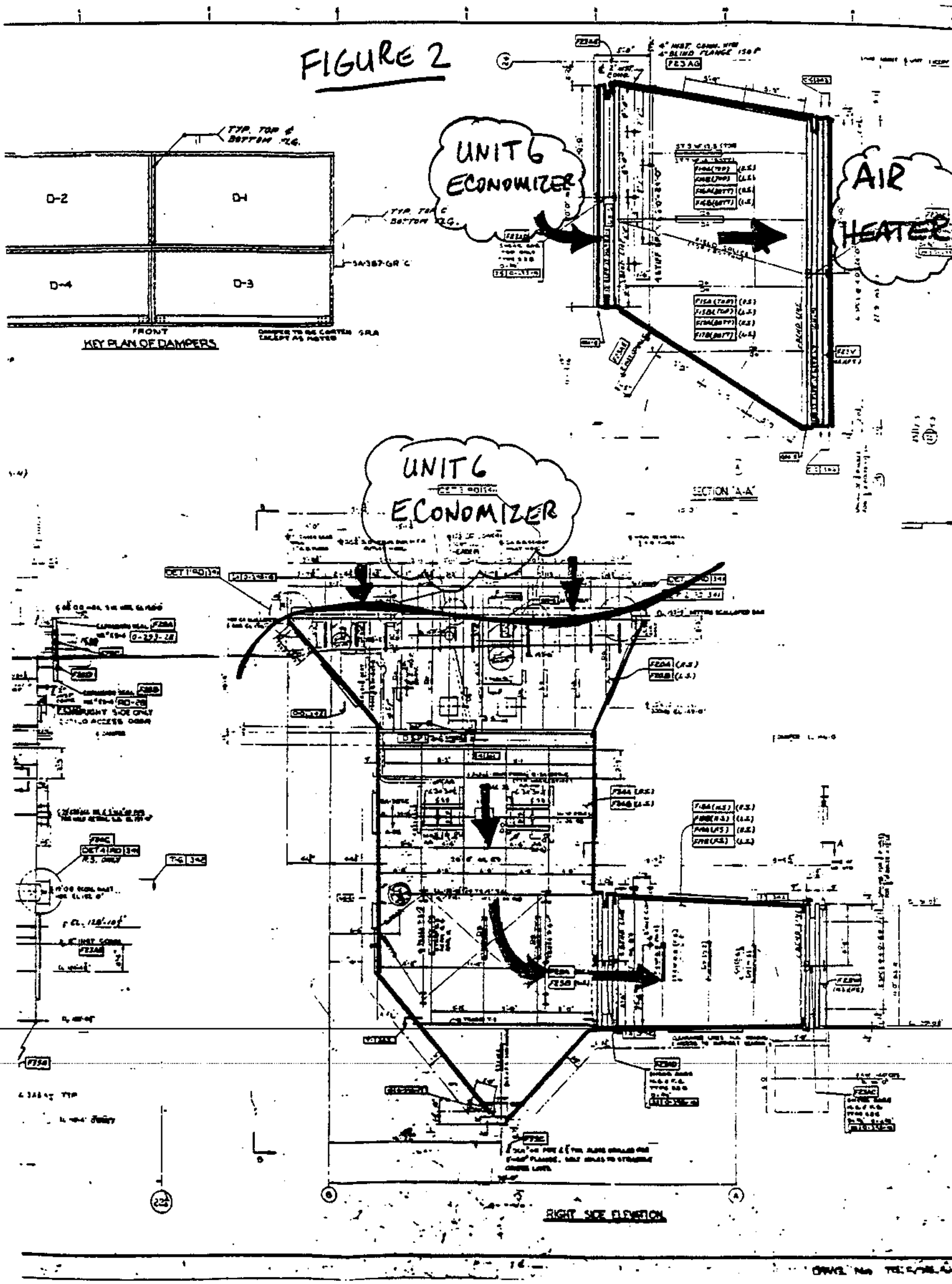

UNIT 6 ECONOMIZER
AIR HEATER
KEY PLAN OF DAMPERS
D-2
D-1
D-4
D-3
FRONT
SECTION "A-A"
UNIT 6 ECONOMIZER
RIGHT SIDE ELEVATION

EXHIBIT 2.1-B

DUCT STATIC PRESSURE MEASUREMENTS BY SOUTHERN RESEARCH INSTITUTE

CRIST UNIT 5 DUCT STATIC PRESSURE
Measurements by Southern Research Institute

Date	Unit	Location	Load	Static Pressure (in H_2O)
7/28/90	5	Inlet	Low	-4.0
7/29/90	5	Inlet	Low	-3.5
7/30/90	5	Inlet	High	-6.5
7/31/90	5	Inlet	High	-6.5
8/2/90	5	Inlet	High	-6.7
8/5/90	5	Outlet	High	-8.3
8/6/90	5	Outlet	High	-8.1

EXHIBIT 2.1-C

FLYASH PARTICULATE SIZE DISTRIBUTION MEASURED BY SOUTHERN RESEARCH INSTITUTE

CRIST UNIT 5 FLYASH PARTICULATE SIZE DISTRIBUTION

Cumulative Weight Percent	Particle Size less than (μ)
95	90
90	57
80	38
60	21
50	16
40	13
20	6.6
10	3.4
1	1.1

Flyash Particulate Size Distributions Measured By
Southern Research Institute
(Page 1 of 3)

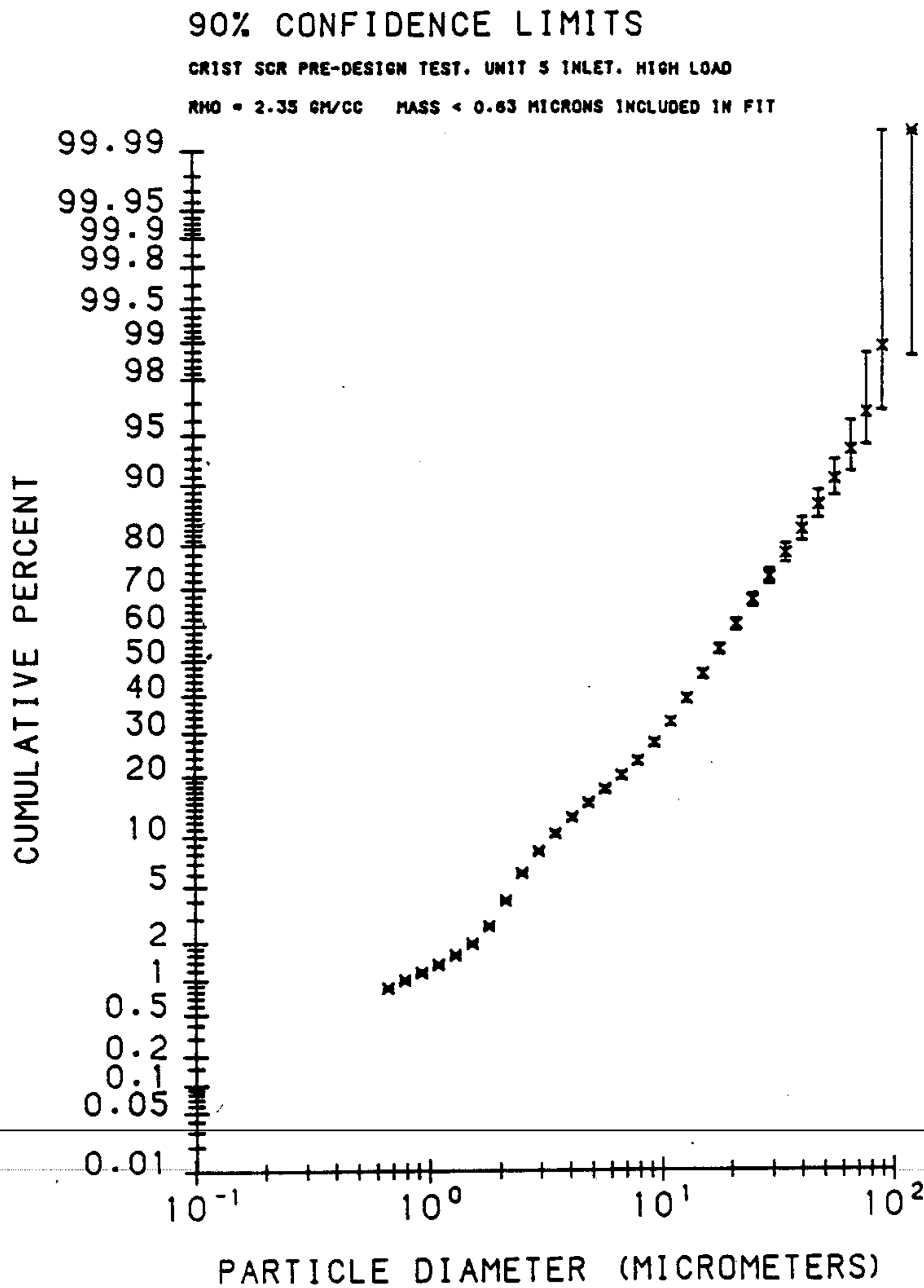


Figure 5. Crist Unit 5 ESP Inlet, High Load, Cumulative Percent Particle Size Distribution.

Flyash Particulate Size Distributions Measured By
Southern Research Institute
(Page 2 of 3)

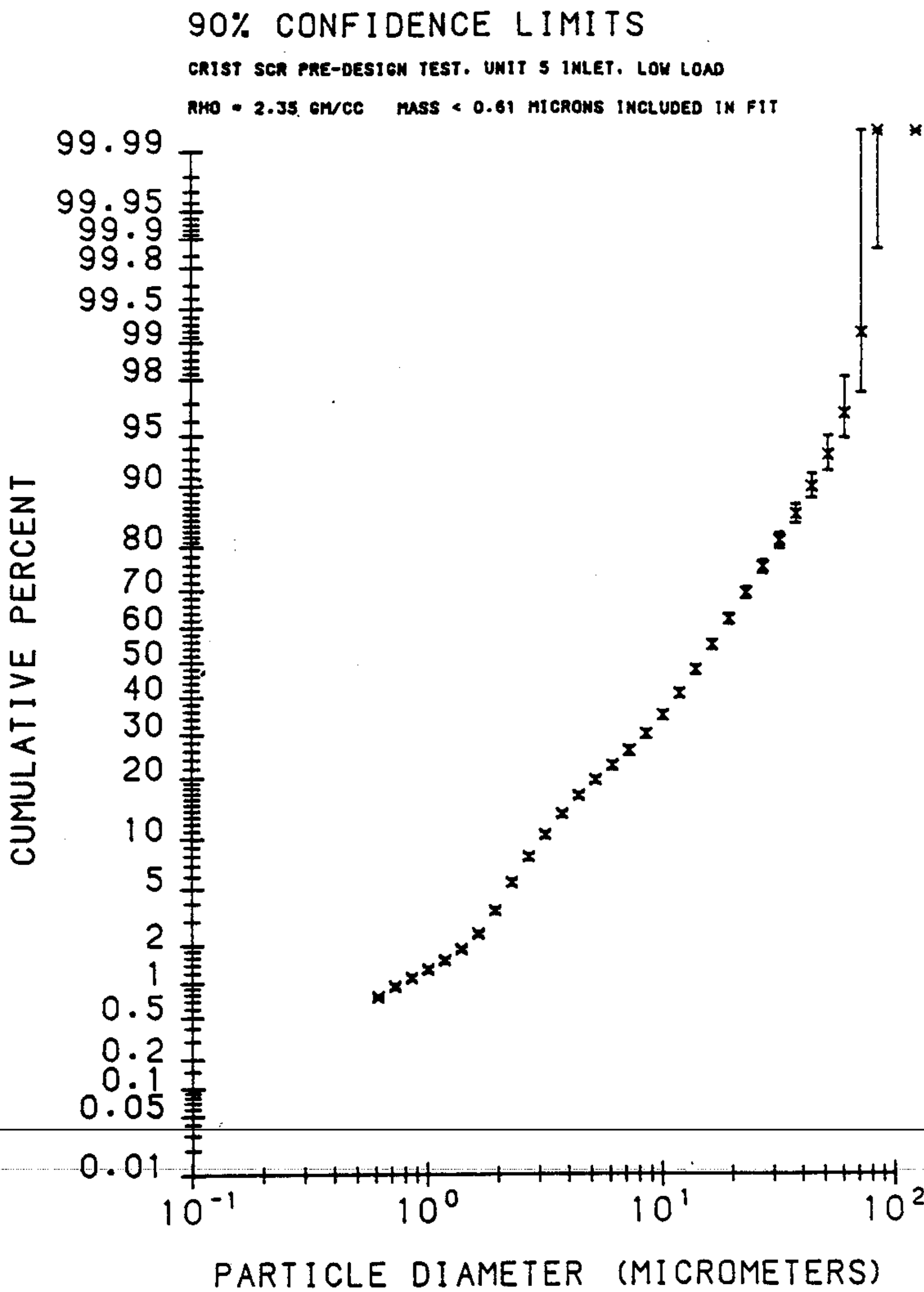


Figure 9. Crist Unit 5 ESP Inlet, Low Load, Cumulative Percent Particle Size Distribution.

Flyash Particulate Size Distributions Measured By
Southern Research Institute
(Page 3 of 3)

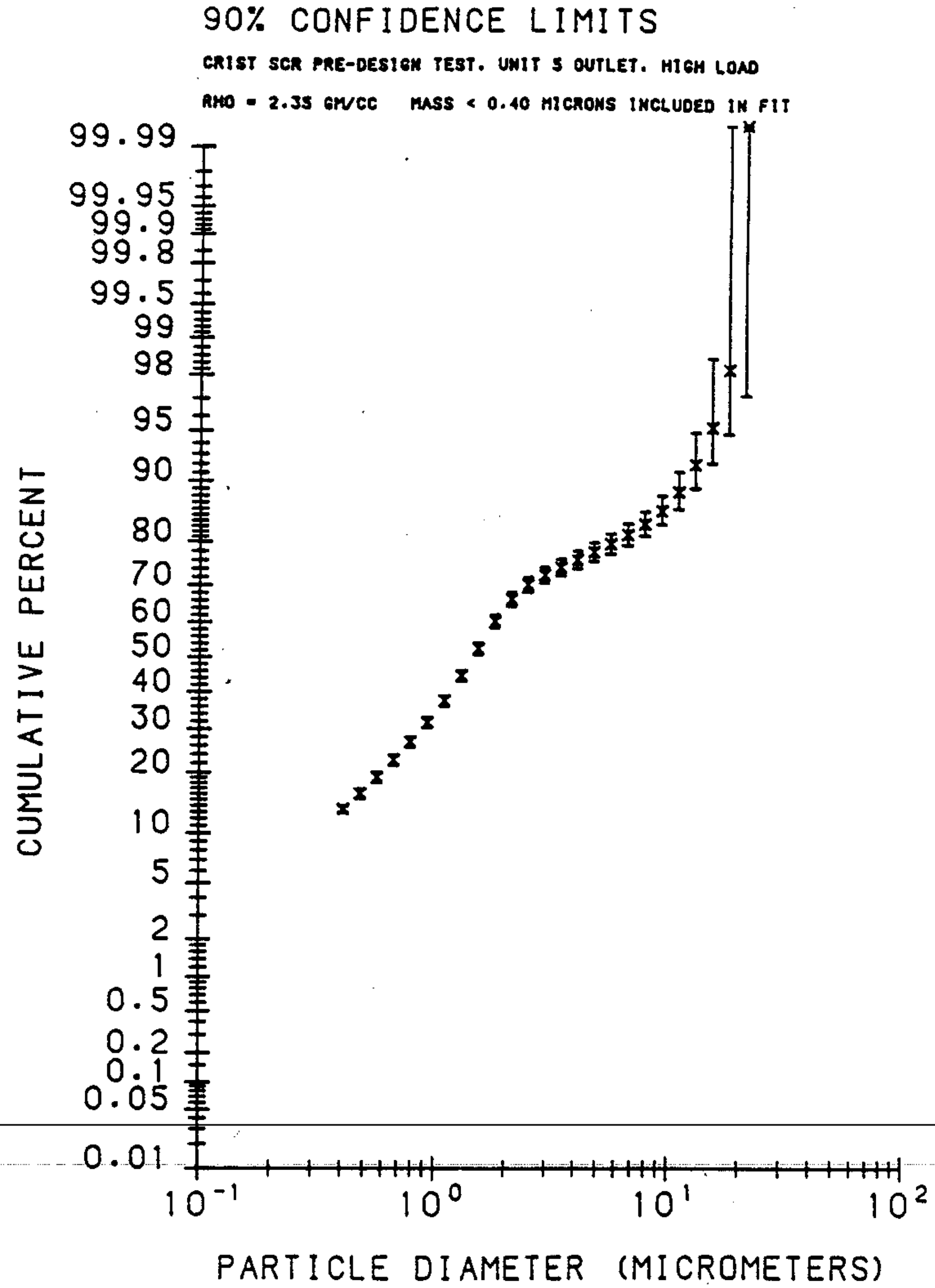


Figure 21. Crist Unit 5 ESP Outlet, High Load, Cumulative Percent Particle Size Distribution.

2.2 SCR CATALYSTS

The SCR test facility will evaluate commercially available SCR catalyst technology obtained from world-wide vendors. It is the intent of SCS to select catalysts that will provide an evaluation of process chemistry and balance of plant integration effects when applying SCR to high-sulfur U.S. coal.

Evaluation agreements have been signed with seven catalyst suppliers. The suppliers, applicable pilot plant reactor size, and catalyst configuration are listed in Table 2.2-1. Supplementary information on catalyst module dimensions are presented in Exhibit 2.2-A.

2.2.1 Proprietary and Non-proprietary Data

Several tests will be conducted throughout the course of the project. Some of these will result in non-proprietary data, both process and laboratory, as well as proprietary laboratory data.

Exhibit 2.2-B presents the non-proprietary process data that will be developed by SCS as part of the operation of the pilot plant.

Exhibit 2.2-C lists non-proprietary laboratory data that will be determined by the catalyst suppliers on samples extracted from the pilot plant. This data essentially consists of activity measurements on samples collected at three month periods, eight samples for the two year program.

Standard laboratory activity tests for the nine catalysts have not been determined. Each catalyst supplier has been queried about parameters that should be considered for lab tests (Exhibit 2.2-D). SCS will review the responses and, if appropriate, construct a uniform set of testing conditions.

TABLE 2.2-1

Catalysts in the DOE/SCS SCR Project

Catalyst Vendor	Reactor Size	Catalyst Configuration
Nippon Shokubai K.K.	Large	Honeycomb
Siemens AG	Large	Plate
W. R. Grace	Large	Honeycomb
Engelhard	Small	Honeycomb (low dust)
Engelhard	Small	Honeycomb (high dust)
Haldor Topsoe	Small	Plate
Hitachi Zosen	Small	Plate
Norton	Small	Honeycomb
W. R. Grace	Small	Honeycomb

2.2.2 Material Safety Data Sheets

SCS will require each catalyst vendor to supply a Material Safety Data Sheets upon shipment of catalyst to the site.

2.2.3 Catalyst Sampling

The exact method of sampling by the catalyst suppliers throughout the program is not known. However, some thought has been given to the effect of sampling on catalyst performance and measurements of the decline in activity for both the large and small reactors. (See EXHIBIT 2.2-E)

As expected, extracting samples from the small reactors will have more impact on the activity measurement than that of the large reactors, since samples extracted from small reactors will constitute a larger percentage of the total intial catalyst volume.

EXHIBIT 2.2-A

SUPPLEMENTARY INFORMATION ON CATALYST MODULE DIMENSIONS

Intracompany Memo — Southern Company Services

DATE: 04-Mar-1991 10:46am CST

RE: Module dimensions 3/4/91

FROM: G. S. Ranhotra
Research & Environmental Affairs
8-821-6624

TO: MAXWELL, J. DOUG

We have obtained revised module dimensions from all suppliers who were originally not in accordance with cross-sections we had selected. Recall that the dimensions selected were based on the initial review of vendor responses.

Large Reactor Module Dimensions

Catalyst	Length (clearance)	Width (clearance)	Depth	No. of Layers	Eff. Volume
SCS Recomm	1.354 m	1.048 m	-	-	-
Vendor Responses					
NSKK	1.354 m	1.048 m	1.100 m	3	3.026 m^3
Siemens	1.354 m (0.010 m)	0.954 m (0.003 m)	1.170 m	2	2.3 m^3
Noxeram	1.354 m (0.010 m)	1.048 m (0.010 m)	1.150 m	3	3.026 m^3

Small Reactor Module Dimensions

Catalyst	Length (clearance)	Width (clearance)	Depth	No. of Layers	Eff. Volume
SCS Recomm	0.318 m	0.318 m	-	-	-
Vendor Responses					
Synox	0.318 m (0.010 m)	0.318 m (0.010 m)	1.150 m	3	0.19 m^3
H. Zosen	0.318 m (0.003 m)	0.318 m (0.003 m)	1.130 m	3	0.25 m^3
Norton	0.318 m	0.318 m	0.889 m	4	0.283 m^3
H. Topsoe	0.321 m (0.002 m)	0.321 m (0.002 m)	0.650 m for 1st & 3rd 1.207 m for 2nd	3	0.189 m^3
Engelhard	0.318 m	0.318 m	0.381 m or 0.762 m for the two double module layers	3	0.1178 m^3
Engelhard	0.318 m	0.318 m	0.381 m	2	0.053 m^3

Even though module dimensions are similar now, the vendors differ on their recommendations for clearance. It would appear that a clearance between the module and reactor of 0.010 m on each side would satisfy all suppliers. This would also allow us to accommodate Topsoe's slightly larger module. Guide vanes may be required for the Siemens catalyst or, since it is the only large plate catalyst, the reactor could be designed for it alone.

cc: HEALY, EDWARD C.
BOWERS, KERRY W.
SEARS, ROD E.

EXHIBIT 2.2-B

NON-PROPRIETARY PROCESS DATA TO BE DEVELOPED BY SOUTHERN COMPANY SERVICES

Non-Proprietary Process Data to be Developed by SCS

1. Flue gas composition.

2. Flyash loading, particle size and composition.

3. Ammonia-to-NOx ratio.

4. DeNOx performance and ammonia slip under various operating conditions over the two year test program.

5. Flue gas temperature.

6. Linear, Area and Space Velocities.

7. SO2 to SO3 Conversion percentage.

8. Pressure Drop.

9. Air Preheater Performance Data (Large Reactors only).

10 Operational problems (if any) such as: catalyst plugging, high sootblowing requirements, high pressure drop, excessive air preheater pluggage, etc. (or other problems as noted).

EXHIBIT 2.2-C

NON-PROPRIETARY LABORATORY DATA

Non-Proprietary Laboratory Data to be Developed by Nippon Shokubai

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Eight (8) samples collected by SCS from the Plant Crist SCR facility at three month intervals during the two year testing period.

Non-Proprietary Laboratory Data to be Developed by Siemens

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Samples collected by SCS from the Plant Crist SCR facility during the two year testing period.

Non-Proprietary Laboratory Data to be Developed by W. R. Grace

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Eight (8) samples collected by SCS from the Plant Crist SCR facility at three month intervals during the two year testing period.

2. Determination of qualitative catalyst activity failure mechanism, if any.

Non-Proprietary Laboratory Data to be Developed by Hitachi Zosen

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Eight (8) samples collected by SCS from the Plant Crist SCR facility at three month intervals during the two year testing period.

Non-Proprietary Laboratory Data to be Developed by Norton

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Eight (8) samples collected by SCS from the Plant Crist SCR facility at three month intervals during the two year testing period.

Non-Proprietary Laboratory Data to be Developed by Haldor Topsoe

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Eight (8) samples collected by SCS from the Plant Crist SCR facility at three month intervals during the two year testing period.

JRJ
TB

Non-Proprietary Laboratory Data to be Developed by Engelhard

1. Catalyst activity data using laboratory reactor(s) operating under conditions agreed to by SCS and catalyst supplier. Laboratory activity measurements will be performed on:

   a. Fresh catalyst at the beginning of the testing phase, and

   b. Eight (8) samples collected by SCS from the Plant Crist SCR facility at three month intervals during the two year testing period.

EXHIBIT 2.2-D

STANDARD ACTIVITY TEST PARAMETERS

STANDARD ACTIVITY TEST PARAMETERS

Per the Evaluation Agreement reached between Southern Company Services (SCS) and each catalyst supplier, catalyst activity data will be measured using laboratory reactor(s) operating under conditions agreed to by SCS and the catalyst supplier. SCS wishes to remove large variations in laboratory activity test procedures of SCR catalysts between the various suppliers. SCS is requesting comment on the testing parameters as listed below. We wish to obtain each supplier's recommendation for what he considers are the most appropriate test conditions to determine differences in activity (NOx conversion) and selectivity (SO_2 oxidation) during the course of the 2 year DOE/SCS SCR project. SCS will assess the catalyst suppliers' comments and recommendations and attempt to develop a uniform set of testing conditions.

Eight areas of testing parameters are listed below for review and comment. Within each area additional points/questions are included for clarification. We request that you provide a description of laboratory procedures that address each of the points listed below and a labeled schematic/sketch of the laboratory test apparatus and related equipment (e.g., analytical instruments and feed gas delivery system). Some of the points/concerns under these areas, though, may not necessarily apply to an individual catalyst. If so, please provide explanatory comments. Also, if you find that we have left off an important issue, please list and describe separately, and explain why that issue is important.

<u>Testing Parameters</u>

I. **Catalyst Preparation:**

a. What are the shape and size of catalysts tested in the lab reactor?
   Is the surface area/volume ratio a critical parameter, and if so, what is the desired value?
b. What is the void volume in the reactor?
   Is channeling in the lab reactor a concern and how is it addressed?
c. Sample usage for activity and analytical tests.
   Will catalyst pieces for activity and analytical testing be obtained from the same sample removed from the pilot reactor?
d. Removal of flyash from catalyst surface
   Is this necessary or is it better to measure the influence of flyash, e.g. adsorbed ammonium bisulfate?
e. What is the minimum catalyst volume (weight) for accuracy?

2. **Catalyst Pretreatment (Startup):**

   a. What is the gas composition for pretreatment (e.g. SO_2, NH_3, O_2, NO_x, H_2O, etc.)?
      Is a presulfiding or similar step required, and if so, what are the conditions used?
   b. Sequence of addition of gases and duration of exposure to catalyst.
      Is the reactor bypassed when adjusting gas composition?
   c. What is the rate of heatup?
   d. What are the initial and final temperatures?
   e. Gas flow (total volume passed through reactor) and its relative importance.
   f. System pressure.

3. **Reactor Design:**

   a. Dual bed reactor, for side by side comparison with same feed, versus single bed measurements of fresh and spent catalyst, and reasoning for preference.
   b. What are the internal diameter and length of the reactor?
   c. Adiabatic or isothermal operation?
   d. Flow regime prior to and following catalyst.
      How important is it to maintain laminar flow?
   e. Location of thermowell(s) and influence on catalyst packing.
      How many and where are temperature measurements taken? What effect is there on the flow regime?
   f. Amount, size, and location of glass wool/glass beads for mixing.
   g. External heating jacket
      How are the reactor and connecting lines heated?
   h. Preheaters, if any.
   i. Upflow or downflow of reactant gases.
   j. Pressure regulators, if any.

4. **Measurement Devices:**

   a. Analytical instruments description with sensitivities and detection limits.
   b. Heated lines to prevent condensation of H_2SO_4, ABS, NH_3, etc.?
   c. Description of mass flow controllers (or similar device used to measure flow) and their accuracies.
      Will the flow over long periods be verified with wet test meter or similar device?
   d. How will samples be handled?

5. **Feed Gas Preparation:**

   a. How will feed gas be prepared?
   b. If feed gas is premixed, what type of cylinders are to be used?
   c. How will adsorption on walls of cylinders be avoided (e.g. for SO_3, NH_3, etc.)?
   d. Will NH_3 and SO_3 have to be kept separated?

6. **Operating Conditions:**

   a. Area/space velocity.
   b. Temperature.
   c. Linear velocity.
   d. Ammonia/NOx ratio.
   e. NO level.
   f. NO_2 level.
   g. SO_2 level.
   h. SO_3 level.
   i. O_2 level.
   j. H_2O level.
   k. N_2 level.
   l. Impurities.
      Are there any in the feed that could be of concern and how addressed?
   m. How will steady state be verified?
   n. Are there different operating conditions for determining activity and selectivity?
   o. Empty reactor tests for NH_3 and SO_2 oxidation.
   p. Pressure of reactor, permitted pressure drop.

7. **Data Reduction and Analysis:**

   a. Continuous or intermittent analysis of inlet/outlet gas compositions and specific analysis frequency?
   b. Temperature recorder.
      What type will be used; is it continuous?
   c. How will side reactions be accounted for?
      For instance, ABS, AS, NH_4NO_3, N_2O, SO_3 formation.
   d. Account for relative influences of mass transfer to catalyst surface (through pore structure, etc.) and intrinsic activity.
   e. Analysis of catalyst properties before and after test.
      Is there a need to determine oxidation state or perform XRD, XRF for poisons, BET surface area, PVD?

8. **Reactor Shutdown:**

   a. What procedure is recommended?
   b. Sequence of gases.
      Is there any particular order during shutdown?
   c. Temperature reduction.
      What is cool down rate; is it important if catalysts are to be analyzed following lab tests?
   d. Unloading of reactor.
      Any specific procedures needed which may influence any tests to be conducted on catalyst after laboratory activity tests?

EXHIBIT 2.2-E

EFFECT OF CATALYST SAMPLING

Intracompany Memo Southern Company Services

DATE: 12-Sep-1990 07:11am CST

RE: Catalyst Sampling

FROM: G. S. Ranhotra
Research & Environmental
8-821-6624

TO: BOWERS, KERRY W.

Large Reactor Analysis

The catalyst sampling philosophy currently in place calls for extracting catalyst elements from the large reactor (one of a total of 48 in any given bed of the three bed reactor) every three months. I do not believe that any of the vendors whose catalysts are in the large reactors have objected to this. This sampling frequency would amount to 8 elements from each bed over the course of the test program. If samples are collected from each bed every three months, the total catalyst replaced would be 24/144 or 16.67%.

The question can be raised as to whether this percentage is too high. Will the effect on the measured activity be too great? To answer this, we can look at the contribution to the total activity of the elements of varying ages. Since the greatest amount of replacement will have occurred by the end of the test period, we can examine this point in time. In order to calculate the contribution to activity, a rate of deactivation has to be assumed. The logarithmic expression proposed by Haldor Topsoe (which by its nature predicts high deactivation at first and then a decreasing rate of deactivation) appears reasonable.

$$\ln(k/k_0)=-d(t)$$

k = activity constant at time t
k_0= initial activity
d = deactivation rate, months $^{-1}$
t = age of catalyst in months

The rate expression which corresponds to this type of activity constant, k, is of the form shown below.

$$\text{Conversion} = (NH3/NOx)_{in}\ (1 - e^{-k/GHSV})$$

Based on data provided by Siemens and BHKK, an average d can be estimated. For the Siemens data which shows activity (assumed to be k) declining from 100% to 75% over 16000 hours in a high dust environment, a d of 0.012 is determined. From BHKK's drop in conversion of 78.5% to 77.7% over 2 years, a value of 0.0087 is determined. An average d of 0.0104 is used from hereon.

A table showing the contribution to conversion by catalyst elements of various ages (by applying the d calculated above) is given below. The data for Grace's NOXERAM catalyst is used for this example, i.e. 0.813 NH_3/NO_x and 80% conversion at 2 years life. k_o is backcalculated from this data and used in the determination of k/k_o at various stages of aging.

No. of Elements	Age @ End of Test	k/k_o	% Conversion
123	24 months	0.7799	80.00
3	21 months	0.8045	80.16
3	18 months	0.8299	80.30
3	15 months	0.8561	80.43
3	12 months	0.8831	80.55
3	9 months	0.9110	80.65
3	6 months	0.9397	80.74
3	3 months	0.9694	80.82
144			
	Initially	1.0000	80.90

There is one major assumption that went into constructing the above table that should be noted. It is assumed that the three elements removed from the reactor at any of the sampling periods were from only one vertical slice. Doing so allows the use of the overall reactor d to calculate the contribution to activity of the slice in question. In terms of correlating differences in activity between catalyst beds, it makes sense to sample elements in a vertical slice. For instance, there may be major differences in distribution of poisons or temperature across the cross section of the reactor. Elements in a vertical slice are more likely to be exposed to similar environments that those which are not.

Taking a weighted-average of the contributions to conversion, an overall reactor deNOx activity of 80.08% is calculated, as compared to 80.00% if no sampling had taken place. Thus the impact on activity measurement at 16.67% catalyst volume replacement is not too great.

Small Reactor Analysis

For the small reactors, it is clearly not easy to sample 1/48 of a bed every three months. Coring individual honeycomb elements into 9 sections (as done by KHI at the TVA site) would produce samples the equivalent of 1/36 of the bed. It is not clear how easily this could be done by all the vendors with catalysts in the small reactors, particularly the plate-type catalysts and the high cell density catalysts. Coring just one element (in the case of a 2x2 array of standard HC elements) is not acceptable if we wish to obtain samples throughout the cross section of the reactor. Preliminary conversations with the catalyst vendors have indicated that they would prefer that sampling frequency be reduced.

Aside from the restrictions on how many samples may be taken over the course of the program is the idea of the impact on activity measurements. Since fewer samples will probably be taken from the small reactors than for the large reactors, the impact will undoubtedly be even lower for the small reactors. A means for reducing the impact even more is to have an aging volume of catalyst in a fourth bed of the reactor (for a conventional three bed arrangement). The advantages include not only the ability to replace catalyst with catalyst of the same age (and hopefully similar deactivation), but also to have on hand a reservoir of aged catalyst in case any operational difficulties damage the catalyst.

If the sampling frequency is to be scaled back in the case of the small reactors, one approach that might be taken is as follows.

Time On Stream	Bed 1	Bed 2	Bed 3
0 months			
3 months	x	x	x
6 months	x		
9 months			
12 months	x	x	x
15 months			
18 months	x		
21 months			
24 months	x	x	x

Note that testing of the first bed is more frequent at first and that beds 2 and 3 are not sampled as often. It is also assumed that we would wish to collect sample throughout the cross section of the bed, in the event that there are any cross-sectional variations in temperature, poisons, etc.. Therefore, more than one element of the proposed 2x2 array will likely be cored. Sampling beds 2 and 3 less frequently would minimize the coring of elements in these beds and lessen any negative impact from coring that might result. (This point should be verified with the vendors.)

Following a format similar to that used in calculating the contributions to activity for the large reactor, conversions can be calculated for the small reactor. Data for the NOXERAM-type catalyst will be used for this example, though attention will be focused on the conversions following the first bed only as well as only the ages proposed in the above sampling scheme. The focus is directed to the first bed conversions alone because the first bed is sampled more frequently than the rest of the beds.

Age @ End of Test	k/k_0	% Conversion (after 1'st Bed)
24 months	0.7799	60.82
21 months	0.8045	61.69
18 months	0.8299	62.55
12 months	0.8831	64.23
6 months	0.9397	65.86
Initially	1.0000	67.42

The weighted-average conversion of the first bed depends on the size of the sample element chosen. If a 2"x2" core is used as the sample element, effectively 1/36 of the bed volume would be sampled at any given time. The impact of this and other sample sizes on overall bed conversion is given below.

Sample Size (as fraction of bed)	Weighted-Average Conversion of 1'st Bed at end of 2 years
1/36	61.13%
1/16	61.51%
1/8	62.20%
1/4 (one whole element)	63.58%
No sampling	60.82%

Recall the above strategy assumes replacement with fresh catalyst and does not consider an aging bed. Note from the above results the greater departure from the conversion-with-no-sampling (60.82%) as one goes to a larger sample size. Clearly replacing a whole element with a fresh catalyst element will greatly influence the bed activity. Also note that in the analysis of only the first bed the same overall reactor deactivation rate as before, d, was used. A higher deactivation rate for the first bed, as might be expected in the case of poisons, greater erosion, or masking, would make the differences more dramatic.

One last note of caution, if we did have to replace whole elements at a time, it would be important that our extractive gas sampling system is not restriced to positions below replacement catalyst. The ideal situation would be to traverse a large portion of the cross-section to obtain individual contributions to conversion as well as an accurate weighted-average.

This pretty much wraps up my thoughts up to now on some of the sampling issues, though I'm sure that there are other design issues such as sample withdrawal that Ed and Rod may address. I have not examined the situation with the two-bed catalysts (SYNOX, Engelhard 100 cpsi, Haldor Topsoe), but a similar analysis can be applied. Let me know if you have questions on the points I've raised.

cc: SEARS, ROD E.
HEALY, EDWARD

2.3 SCR PILOT PLANT

2.3.1 Preliminary Pilot Plant Layout

The prelimnary layout of the SCR pilot plant at Plant Crist is shown in Figures 2.3-1 through 2.3-8. Plant Crist is located approximately at sea level. However, the plant site datum elevation for grade elevation is 90'0".

Plant Crist Unit 5 operates retrofitted hot-side ESP in series with cold-side ESPs. Due to the difficulty of retrofitting the hot-side ESPs, flue gas exits the boiler in a split flow configuration. Consequently, the Unit 5 hot-side ESP has two inlet ducts and two outlet ducts. The high dust extraction location is on the west side of the hot-side ESP inlet duct. The low dust extraction location is on the east side of the hot-side ESP outlet duct. This configuration was chosen to prevent any bias of the low dust sample being extracted downstream of the high dust sample.

The SCR pilot plant control room has been relocated from the pilot plant structure to the roof of an existing plant structure. The control room layout is shown in Section 11.0, Area 900.

2.3.2 Process Description

<u>Reactor Train Designation</u>

Each SCR catalyst will be assigned to a separate reactor. The designation of the different reactor trains, which reflects the assignment of SCR catalysts, is as follows:

Reactor Train	Reactor Size	Unit	Dust Loading	Catalyst Supplier	Catalyst
A	Large	5	High	W.R. Grace	HC-V_2O_5/TiO_2 (Noxeram)
B	Large	5	High	Nippon Shokubi	HC-$V_2O_5/TiO_2/SiO_2$
C	Large	5	High	Siemens	Plate-V_2O_5/TiO_2
D	Small	5	High	Hitachi Zosen	Plate-V_2O_5/TiO_2
E	Small	5	High	W.R. Grace	HC-$V_2O_5/TiO_2/SiO_2$ (Synox)

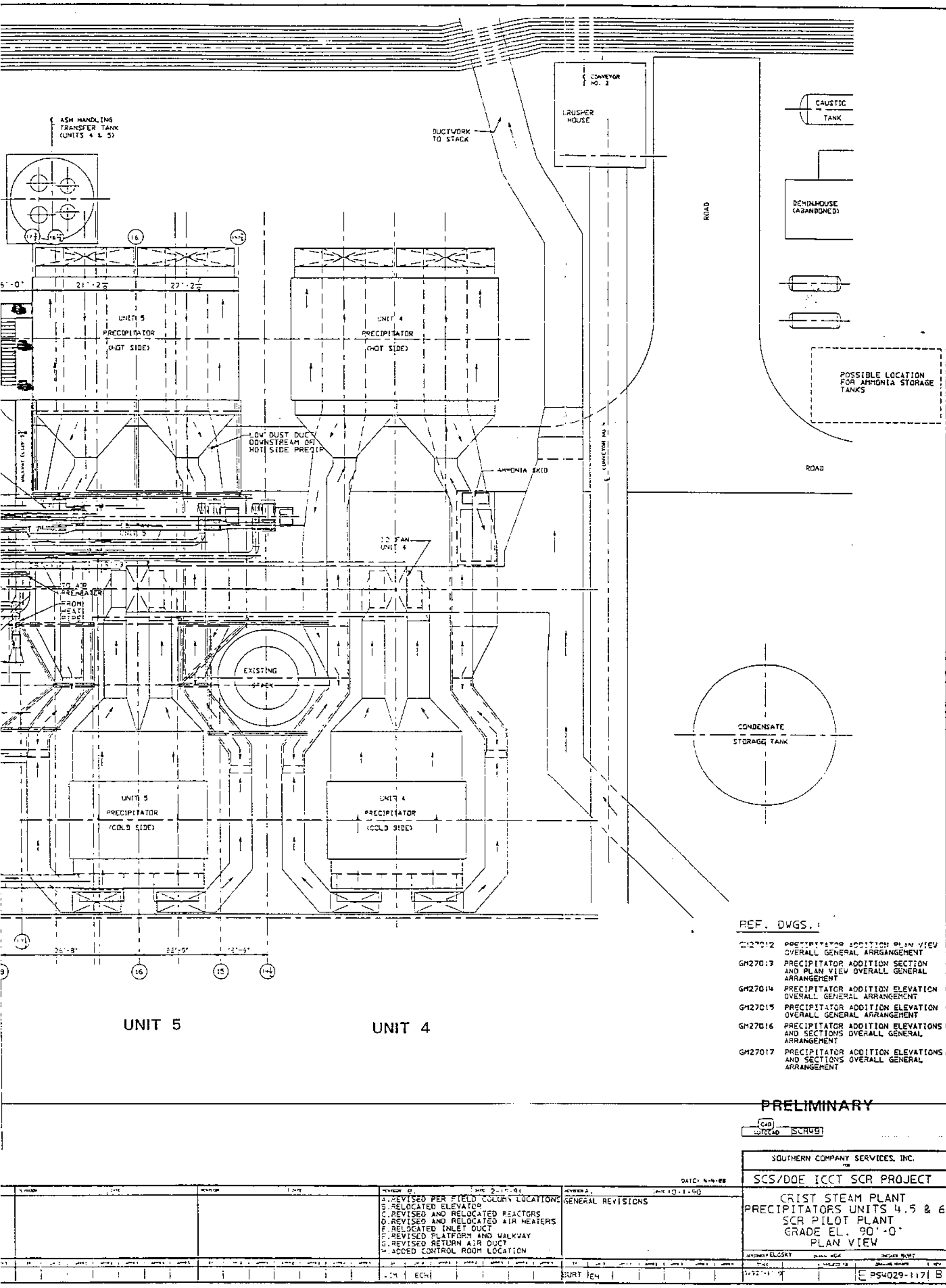


Figure 2.3-1
Plan view. Grade elevation, 90 ft.

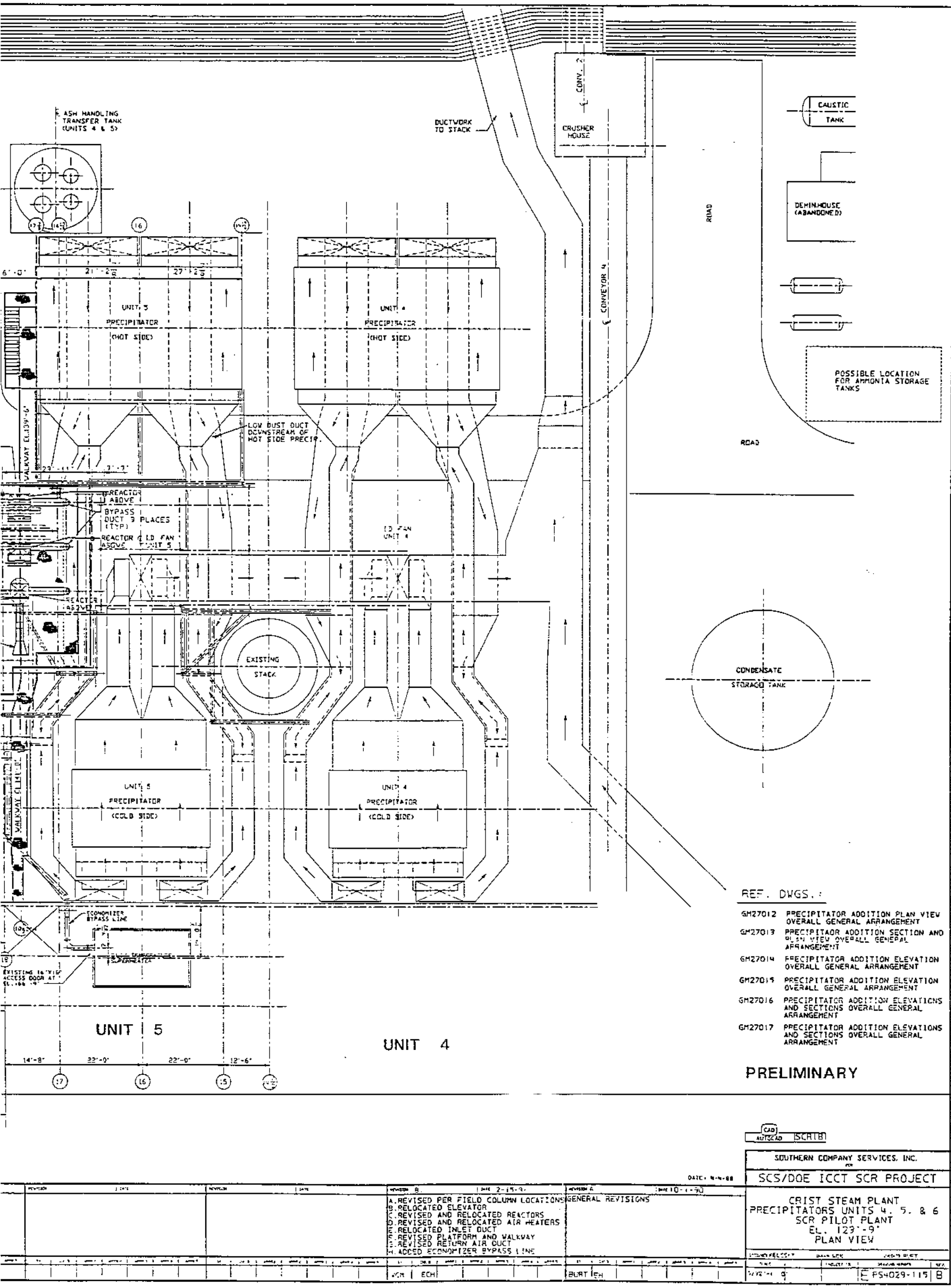


Figure 2.3-2
Plan view. Air preheater elevation, 123 ft, 9 in.

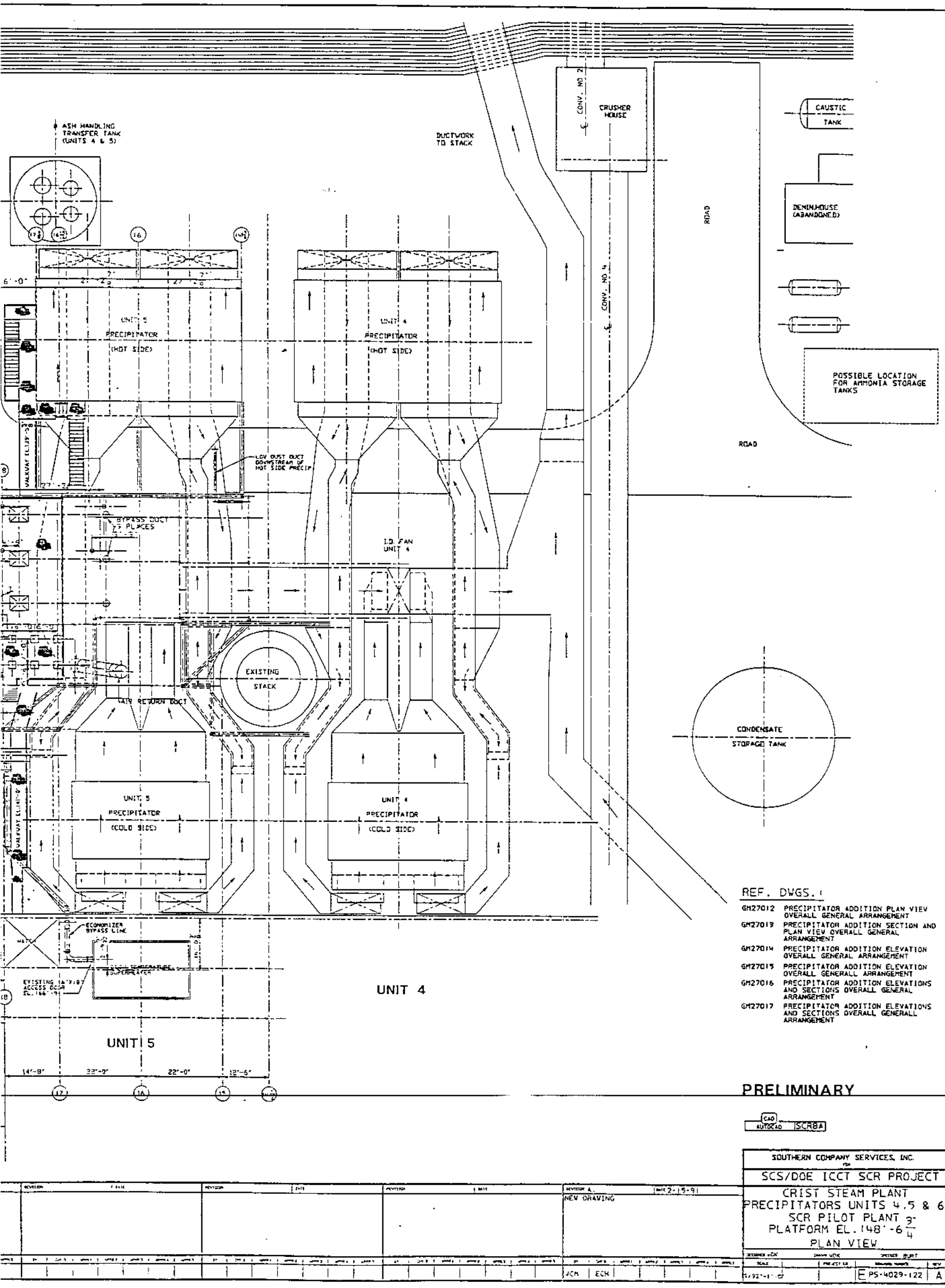


Figure 2.3-3
Plan view. Fourth catalyst elevation, 148 ft, 6-¾ in.

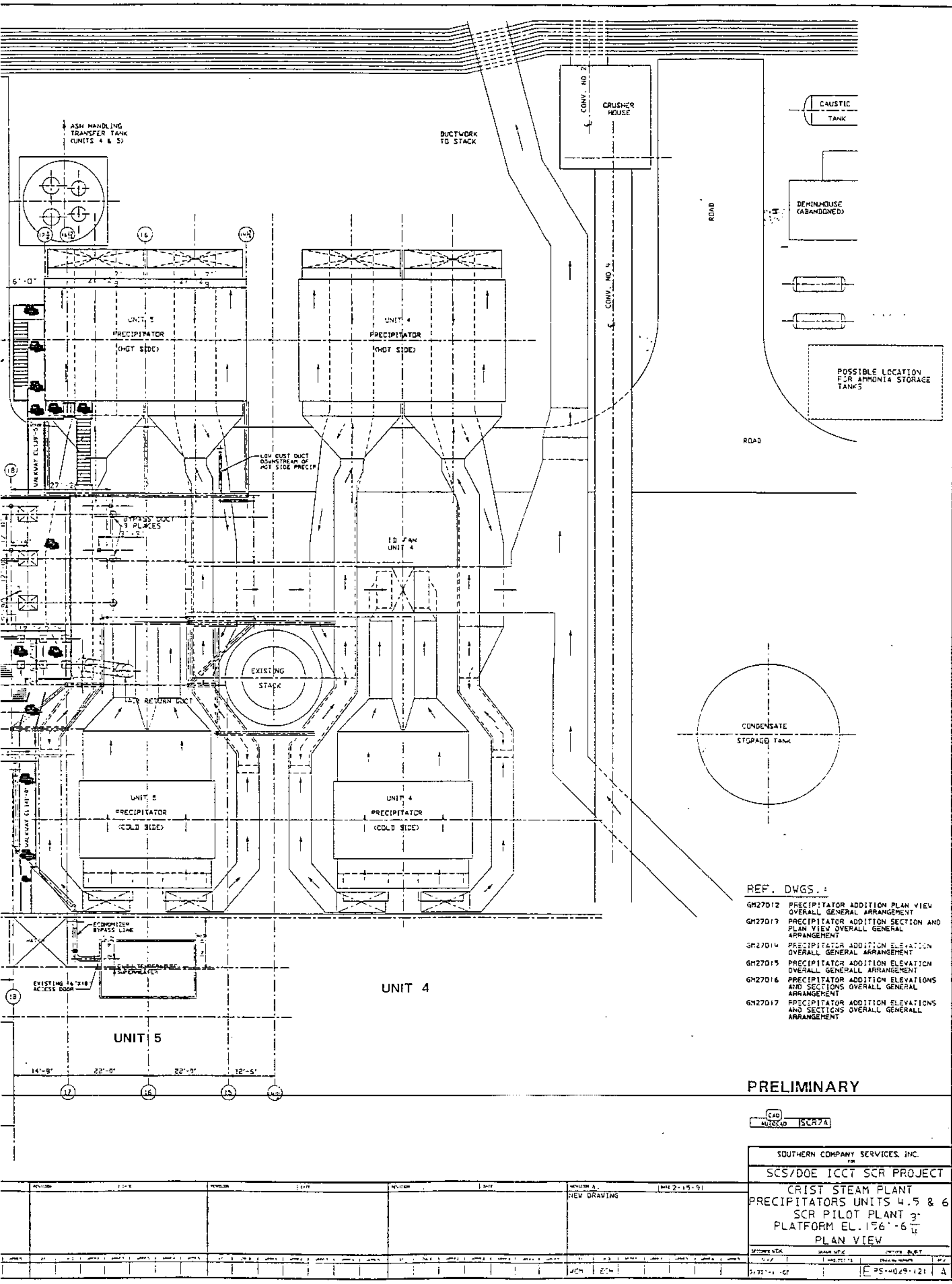


Figure 2.3-4
Plan view. Third catalyst elevation, 156 ft, 6-¾ in.

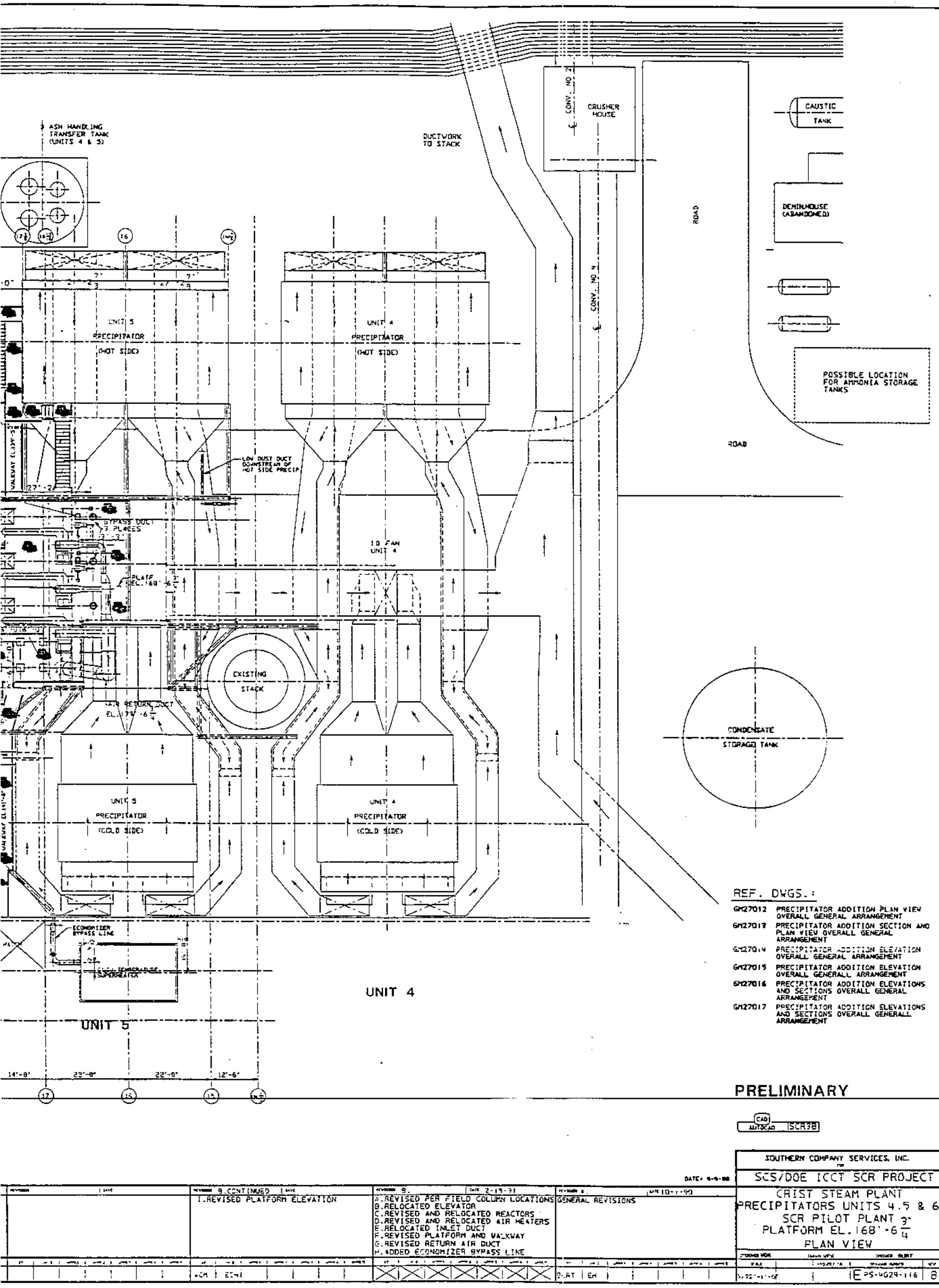


Figure 2.3-5
Plan view. Second catalyst elevation, 168 ft, 6-¾ in.

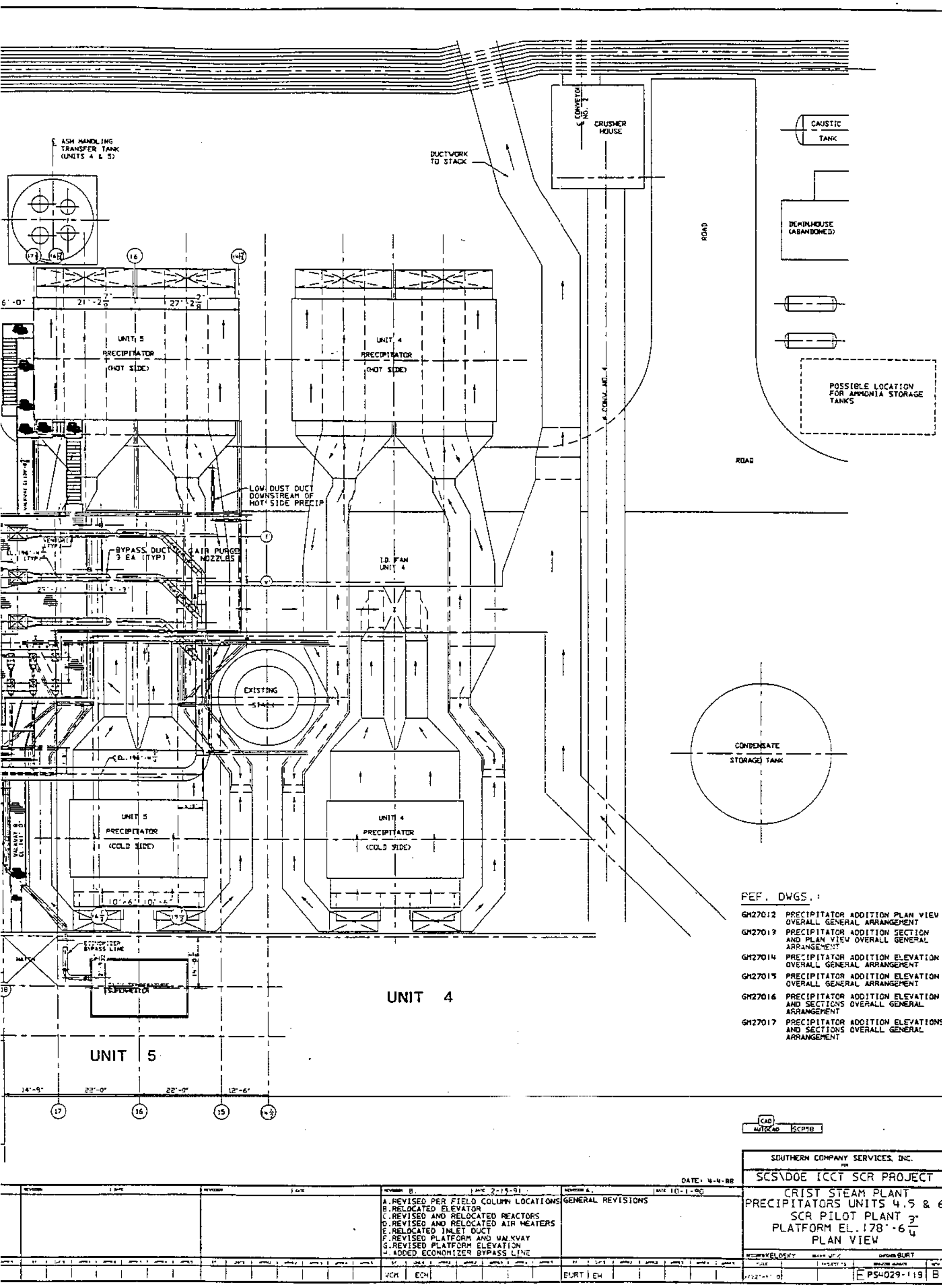


Figure 2.3-6
Plan view. First catalyst elevation, 178 ft, 6-¾ in.

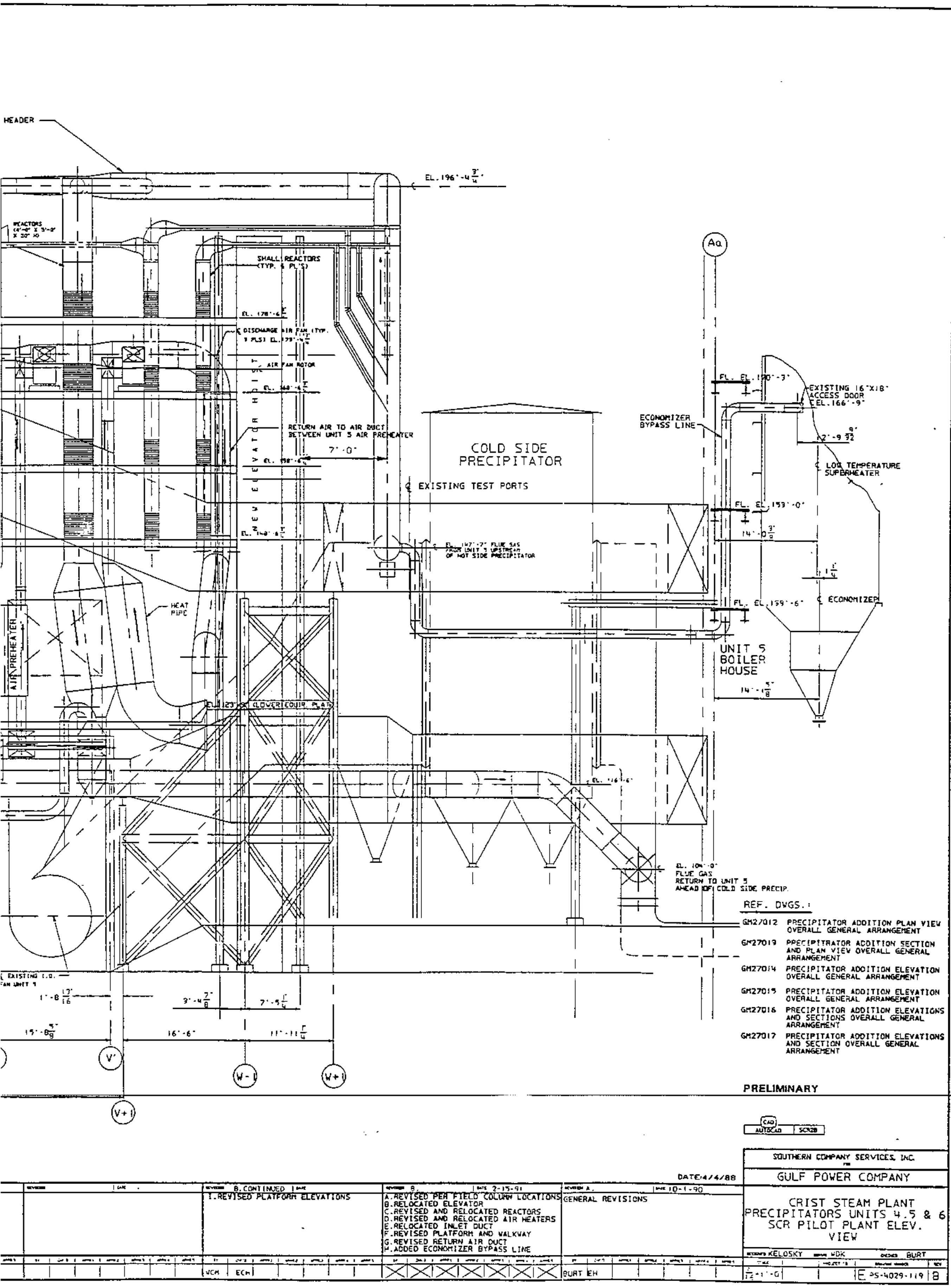


Figure 2.3-7
West elevation view.

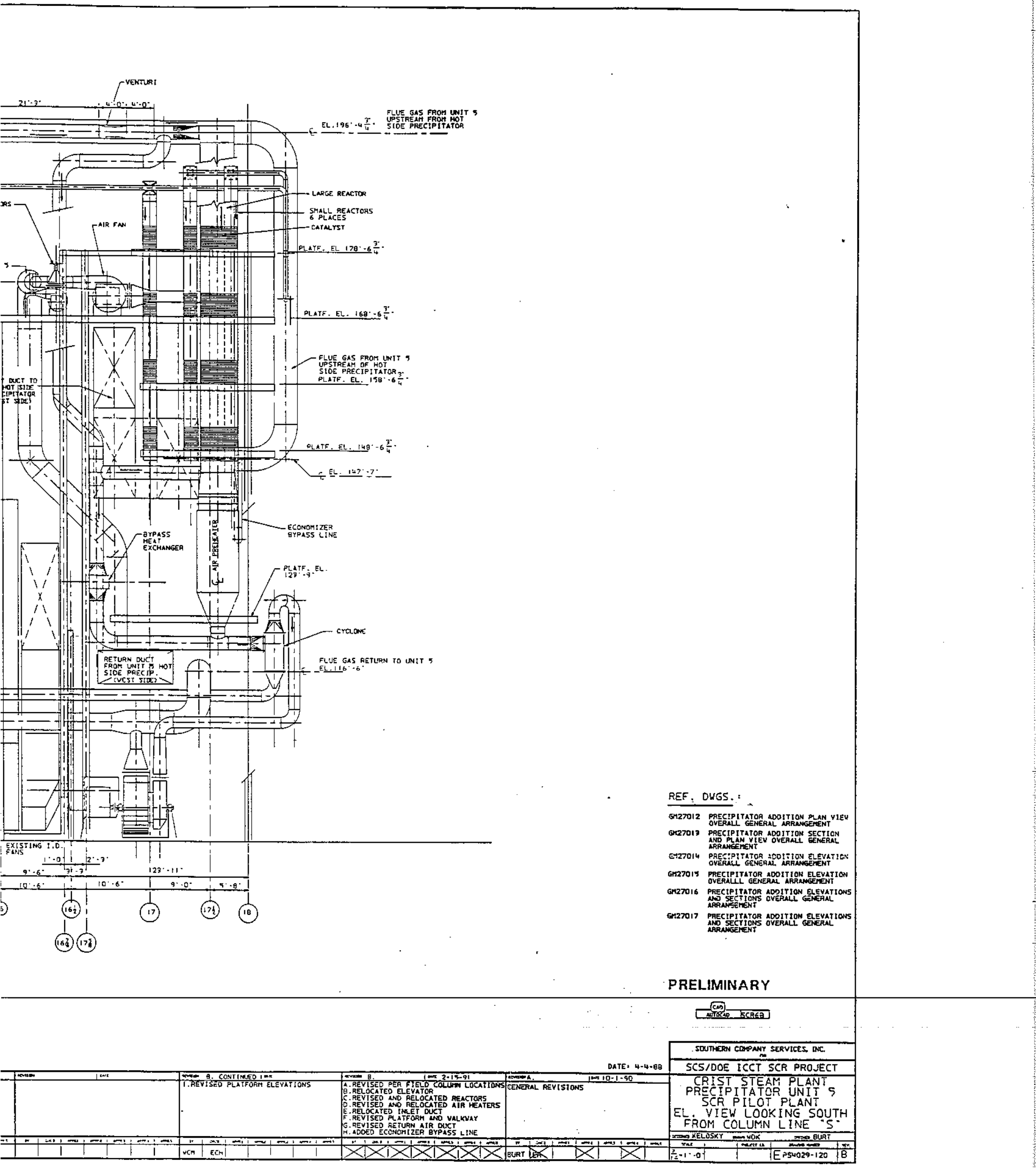


Figure 2.3-8
South elevation view, column line S.

Continued from page 2.3-1

F	Small	5	High	Norton	HC-Zeolite w/V_2O_5
G	Small	5	High	Engelhard	HC-Coated V_2O_5/TiO_2
H	Small	5	High	Haldor Topsoe	Plate-V_2O_5/TiO_2
J	Small	5	Low	Engelhard	HC-Coated V_2O_5/TiO_2

HC = Honeycomb

Area Designation

The SCR pilot plant is divided into areas. These area descriptions are as follow:

Area	Description
100	Flue Gas Extraction Scoop to Flue Gas Distribution Header
200	Flue Gas Distribution Header to Reactor Inlet
300	Ammonia Storage to Reactors
400	SCR Reactors
500	SCR Reactor Outlet to Pilot APH Outlet
600	Cyclones to Host Boiler Duct
700	Pilot-Plant Air Compressor Station
800	Extractive Gas Sampling System
900	Instrumentation and Controls/Control Room
1000	Utility Systems

Process Flow Diagram

The process flow diagram for the SCR pilot plant is shown in Figure 2.3-9. High-dust flue gas is extracted from the inlet duct on the west side of Unit 5's hot-side ESP. The high-dust flue gas is equally distributed to the three large reactors, 5000-scfm each, and five of the small reactors, 400-scfm each. One small reactor is operated with low dust extracted from the east side hot-side ESP outlet duct for Unit 5. Each reactor train has electric duct heaters to control the temperature of the flue gas and a venturi flow meter to measure the flue gas flow to the reactors. Anhydrous ammonia is independently metered to a stream of dilution air that injects the ammonia via nozzles into the flue gas stream prior to each SCR reactor. An economizer bypass line to the SCR pilot plant maintains a minimum flue gas temperature of 620°F supplied to the pilot plant.

The flue gas and ammonia pass through the SCR reactors, which have the capacity to contain up to four catalyst layers. There is a flow straightening grid (i.e., dummy layer) at the top of the SCR reactors to prevent swirling of the flue gas which could cause erosion problems when catalysts are operated under high-dust conditions. Each catalyst layer is housed in a metal frame commonly referred to as a basket. The catalyst basket is constructed so that the catalyst can be easily loaded into each SCR reactor.

For the large reactor trains, the flue gas exits the reactor and enters a pilot-scale air preheater (APH). The APHs are incorporated to evaluate the effects on downstream equipment using SCR process on flue gas from a high-sulfur coal. The small reactors do not have air preheaters following the SCR reactors. All reactor trains, except the low-dust train J, have a cyclone downstream of the SCR reactors to protect the ID fans from particulates. The small reactors are grouped into three reactors per ID fan.

The exhaust for all the SCR reactors is combined into a single manifold and routed back to the host boiler for reinjection ahead of the cold-side ESP. The preheated air from the APH on the large reactors is also combined into a single manifold and returned to the host boiler draft system, at the air outlet of the existing APH. All the particulates removed from the flue gas with the cyclones are combined and sent to an ash disposal area.

Energy and Material Balance

The material balance for the SCR pilot plant is presented in Table 2.3-1 following the process flow diagram. The description of the stream numbers for the material balance that correspond to the process flow diagram are listed in Table 2.3-2. The standard conditions for the gas calculations are 0°C (32°F), and 1 atmosphere (14.7 psia). English engineering units are used in the material balance.

Table 2.3-2 (Page 1 of 4)

Description of Stream Numbers for the Material Balance

Stream No.	Description
1	High dust flue gas (HDFG) from host boiler
1A	HDFG to pilot plant after economizer bypass junction
2	HDFG to Reactor train A upstream of electric heater
2A	HDFG to Reactor train A downstream of electric heater
3	HDFG to Reactor train B upstream of electric heater
3A	HDFG to Reactor train B downstream of electric heater
4	HDFG to Reactor train C upstream of electric heater
4A	HDFG to Reactor train C downstream of elctric heater
5	HDFG to Reactor train D upstream of electric heater
5A	HDFG to Reactor train D downstream of electric heater
6	HDFG to Reactor train E upstream of electric heater
6A	HDFG to Reactor train E downstream of electric heater
7	HDFG to Reactor train F upstream of electric heater
7A	HDFG to Reactor train F downstream of electric heater
8	HDFG to Reactor train G upstream of electric heater
8A	HDFG to Reactor train G downstream of electric heater
9	HDFG to Reactor train H upstream of electric heater
9A	HDFG to Reactor train H downstream of electric heater
10	Low dust flue gas to Reactor train J upstream of electric heater
10A	Low dust flue gas to Reactor train J downstream of electric heater
11	Ammonia to Reactor train A
12	Injection air to Reactor train A
13	Ammonia/air mixture to Reactor train A
14	Ammonia to Reactor train B
15	Injection air to Reactor train B
16	Ammonia/air mixture to Reactor train B
17	Ammonia to Reactor train C
18	Injection air to Reactor train C
19	Ammonia/air mixture to Reactor train C

Table 2.3-2 (Page 2 of 4)

Stream No.	Description
20	Ammonia to Reactor train D
21	Injection air to Reactor train D
22	Ammonia/air mixture to Reactor train D
23	Ammonia to Reactor train E
24	Injection air to Reactor train E
25	Ammonia/air mixture to Reactor train E
26	Ammonia to Reactor train F
27	Injection air to Reactor train F
28	Ammonia/air mixture to Reactor train F
29	Ammonia to Reactor train G
30	Injection air to Reactor train G
31	Ammonia/air mixture to Reactor train G
32	Ammonia to Reactor train H
33	Injection air to Reactor train H
34	Ammonia/air mixture to Reactor train H
35	Ammonia to Reactor train J
36	Injection air to Reactor train J
37	Ammonia/air mixture to Reactor train J
38	SCR Reactor A inlet
39	SCR Reactor B inlet
40	SCR Reactor C inlet
41	SCR Reactor D inlet
42	SCR Reactor E inlet
43	SCR Reactor F inlet
44	SCR Reactor G inlet
45	SCR Reactor H inlet
46	SCR Reactor J inlet
47	SCR Reactor A outlet
48	SCR Reactor B outlet
49	SCR Reactor C outlet
50	SCR Reactor D outlet
51	SCR Reactor E outlet

Table 2.3-2 (Page 3 of 4)

Stream No.	Description
52	SCR Reactor F outlet
53	SCR Reactor G outlet
~~54~~	~~SCR Reactor H outlet~~
~~55~~	~~SCR Reactor J outlet~~
56	Reactor train A Air Preheater (APH) outlet
57	Reactor train B APH outlet
58	Reactor train C APH outlet
59	Reactor train A APH air inlet
60	Reactor train B APH air inlet
61	Reactor train C APH air inlet
62	Reactor train A APH air outlet
63	Reactor train B APH air outlet
64	Reactor train C APH air outlet
65	Reactor train A cyclone gas outlet
66	Reactor train B cyclone gas outlet
67	Reactor train C cyclone gas outlet
68	Reactor train D cyclone gas outlet
69	Reactor train E cyclone gas outlet
70	Reactor train F cyclone gas outlet
71	Reactor train G cyclone gas outlet
72	Reactor train H cyclone gas outlet
73	Reactor train A cyclone particulate removal
74	Reactor train B cyclone particulate removal
75	Reactor train C cyclone particulate removal
76	Reactor train D cyclone particulate removal
77	Reactor train E cyclone particulate removal
78	Reactor train F cyclone particulate removal
79	Reactor train G cyclone particulate removal
80	Reactor train H cyclone particualte removal
81	Reactor trains D, E & F exhaust gas to fan 602
82	Reactor trains G, H & J exhaust gas to fan 603
83	Deleted

Table 2.3-2 (Page 4 of 4)

Stream No.	Description
84	Deleted
85	Deleted
86	Deleted
87	Deleted
88	Deleted
89	Reactor train A ID Fan outlet
90	Reactor train B ID Fan outlet
91	Reactor train C ID Fan outlet
92	ID Fan F-602 outlet
93	ID Fan F-603 outlet
94	SCR Pilot Plant exhaust gas return
95	Deleted
96	Ammonia from tank to SCR Pilot Plant accumulator
97	High dust flue gas from boiler economizer
98	High dust flue gas to reactor trains A, B, and C
99	High dust flue gas to reactor trains A and B
100	Ammonia dilution air downstream of dilution air electric heater
101	Ammonia dilution air upstream of dilution air electric heater
102	Ammonia dilution air to dilution air fan 301
103	Heated air from reactor trains B (APH-501B) and C (APH-501C)
104	Heated air from reactor trains A (APH-501A), B (APH-501B), and C (APH-501C)
105	Heated air from SCR Pilot Plant to host unit combustion air
106	APH inlet air from heat unit FD fan (upstream of perf plate)
107	APH inlet air to reactor trains A, B, and C
108	AOH inlet air to reactor trains B and C
109	APH from Pilot Plant to host unit ash handling system

Equipment Abbreviations

Equipment abbreviations frequently used in this report are found in Table 2.3-3. Estimated pilot plant equipment weights are provided in Ehibit 2.3-A.

Table 2.3-3

Equipment Abbreviations

Abbreviation	Description
AB	Gas Analyzer Bank
APH	Air Preheater
COM	Compressor
CB	Catalyst Bed
CYC	Cyclone
DMP	Damper
DL	Dummy Catalyst Layer (flow straightener)
DRY	Air Drier
ED	Eductor
F	Fan
FCV	Flow Control Valve
FCD	Flow Control Damper
FE	Flow Element
FIL	Filter
HDR	Header
HTR	Electric Heater
HX	Heat Exchanger
MXR	Mixer
MTR	Motor
OA	Oxygen Analyzer
PRV	Pressure Regulating Valve
PSV	Pressure Safety Valve
RXR	SCR Reactor
SC	Sample Conditioner
SP	Sample Probe
SV	Solenoid Valve
TNK	Tank
TRC	Trap - Condensate (H2O)
TRA	Trap - Ammonia (NH3)
TRS	Trap - Sulfur trixoide (SO3)
VAP	Vacuum Pump

2.3.3 Operational Philosophy

Parametric and Long-term Catalyst Testing

The primary purpose of the SCR demonstration facility is to determine deactivation rates of commercially available SCR catalysts under the exposure of flue gas from high-sulfur U.S. coals. This will be determined by evaluating catalyst deNOx efficiency and other performance variables as a function of three main process variables:

- ammonia-to-NOx ratio
- temperature
- space velocity

The philosophy of operation is to determine baseline performance of each catalyst under design conditions immediately after successful startup. Once baseline conditions have been established, each catalyst will be sequenced through a test matrix that varies each of the above variables around the design point. Appropriate deNOx efficiency, pressure drop, SO_2 oxidation, and ammonia slip will be determined at each test condition. Once the initial parametric test matrix has been completed, each reactor will be returned to baseline design conditions, allowing for steady-state operation over a three-month period, for aging of the catalyst. The parametric test matrix will be repeated for each reactor train once every three months. There will be no more than one reactor train undergoing parametric testing at any one time. The remaining reactors will be either in steady-state operation or off-line.

The following ranges of operating parameters will be adopted for design purposes:

Temperature

Minimum	Baseline (Design Point)	Maximum
620°F	700°F	750°F

The Unit 5 host boiler-economizer outlet temperature ranges between 590°F at low load to 680°F at high load. The pilot plant will maintain a minimun flue gas temperature of 620°F through the use of an economizer bypass.

At full boiler load, the economizer bypass line will be closed and the temperature of the flue gas to the SCR pilot plant will be the boiler-economizer exit temperature minus any heat loss. As boiler load decreases, the boiler-economizer outlet temperature also decreases. When the boiler-economizer exit temperature drops below 620°F, the economizer bypass line will crack open and allow hotter gas extracted from the superheater section of the boiler to blend with the boiler outlet gas. The lower the boiler load, the more bypass gas is required to maintain the 620°F temperature in the SCR pilot plant.

The temperature of the flue gas in each reactor train will be independently controlled, using electric in-duct heaters located upstream of the venturi. The heaters will be designed to boost the flue gas temperature from a minimum of 620°F to the maximum design temperature of 750°F. Detailed discussion of the electric heaters is contained in Section 3.0, Area 200.

Space Velocity

Space velocity is the product of flue gas volume, divided by catalyst volume. SCS will not actually set space velocity. Instead, each catalyst supplier will be required to achieve targeted NOx removal levels for design flue gas volumes and inlet NOx levels. Each supplier will specify the amount of catalyst required to achieve the targeted reductions, which will establish the baseline space velocities. With catalyst volumes thus fixed, variations in flue gas flow rates will alter the space velocity around the design point. Additional gas measurements after each catalyst layer will allow testing of different space velocities while operating at the same linear velocity for a given flowrate.

The following are the design ranges for flue gas flow rates:

Large Reactors

Minimum	Baseline	Maximum
3000 SCFM	5000 SCFM	7500 SCFM

Small Reactors

Minimum	Baseline	Maximum
240 SCFM	400 SCFM	600 SCFM

The flow rate in the reactors will be varied by adjusting the speed on a variable speed motor, so the ID fan will achieve the flow rate adjustment. With the small reactors grouped three per ID fan, an adjustment to the flow rate for one reactor using flow control dampers will result in some balancing of flue gas flow through the bank of reactors, thus obtaining the proper flue gas flow rates in each reactor.

NH_3/NOx Molar Ratio

Minimum	Baseline	Maximum
0.6	0.85	1.1

It should be noted that each the catalyst supplier will specify an NH_3/NOx ratio consistent with their expected catalyst performance. Baseline values varying somewhat from 0.85 are expected, but should not be significantly different. The value of 0.85 will be selected as a baseline design basis. Moreover, the maximum value of 1.1 specifies that the design of the ammonia delivery system will have the capacity to deliver this quantity of ammonia. It is not anticipated that the reactors will be operated in that condition for long periods of time. Rather, this NH_3/NOx value will be used for only short duration testing of the performance of the catalyst under extreme conditions.

Control Precision

It is not sufficient for design of the SCR pilot plants to specify only the above ranges of the process variables. It is also necessary to maintain close control over the precision of the process variables at each test condition. The following describes the required process precision:

Temperature - control to within + or - 2°F at any given operating point.

Flue gas flow - control to within + or - 2 percent of flow on the large reactors (i.e., control to within 100 scfm). On small reactors, control to within + or - 5 percent of flow (i.e., 20 scfm). Since the flow is much smaller, this will actually be harder to accomplish.

Ammonia-to-NOx - control to within 0.005 NH_3/NOx. For the design baseline, this means that NH_3/NOx should range between 0.845 and 0.855 under baseline conditions.

Uniformity

Figure 2.3-10 addresses the importance of controlling the uniformity of gas flow and ammonia distribution. This figure shows the relative increase in catalyst volume needed over the theoretical volume in order to accomodate variations in ammonia distribution, gas flow, and temperature. For the purpose of this program, minimizing the increase in catalyst volume to no more than 1 percent greater than the theoretical volume is anticipated. The following limits are seen in Figure 2.3-10.

Gas flow distribution — Not more than 10 percent deviation (+ or -) in flow velocity or mass flow of flue gas across the cross-section of an individual reactor.

Ammonia distribution — Not more than + or - 5 percent deviation in ammonia distribution. Note however, that ammonia distribution closely controlled at this level is of no value if NOx distribution is also not controlled at this level. The point is that the ammonia and the NOx must match each other, even if the NOx is maldistributed

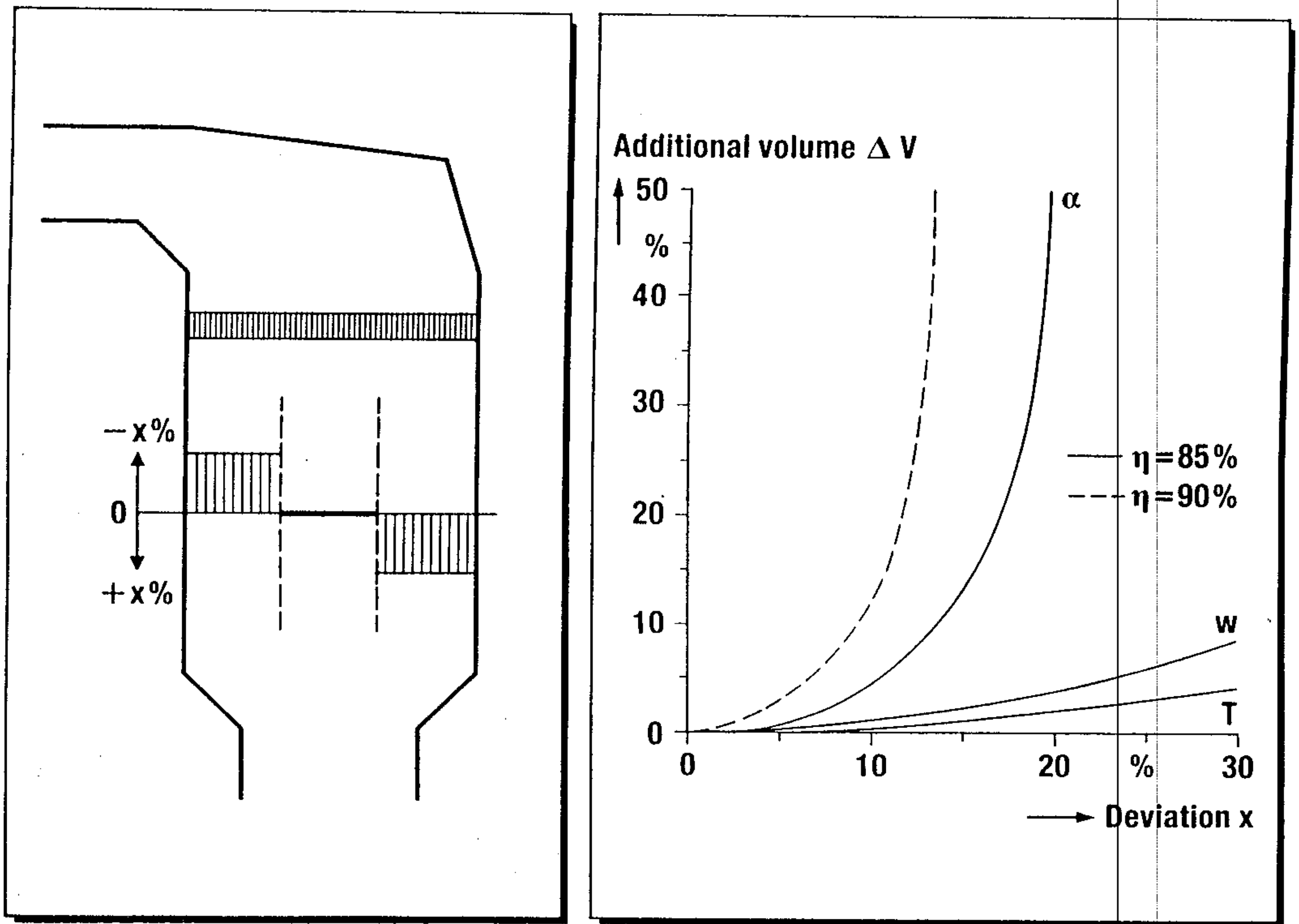


Figure 2.3-10. Uniformity of gas flow and ammonia distribution and limits on catalyst volume.

To ensure proper catalyst aging, the uniformity of fly ash loading and particle size distributions must be controlled, and thus the following limits have been set:

Flyash loading balance — Not more than + or - 5 percent deviation between total mass loading in mg/Nm^3 between individual reactors, and not more than 10 percent deviation in flyash particle size distribution, as determined by cumulative mass vs particle diameter plots.

Air Preheater Testing

The overall objective of the pilot scale LJUNSTROM APH (rotary APH) operation is to adequately simulate the response of existing, full-scale utility APHs if exposed to a post-SCR environment. Proper simulation of full-scale equipment requires maintenance of the following:

- similar gas-side axial temperature profiles, including exit gas temperature.
- identical metal surface temperatures and temperature variations.
- equal pressure drops on both air and gas sides.
- identical rates of air leakage from air to gas side.
- similar fluid mechanics of gas flow and cleaning medium.
- equal air and gas velocities.

Many of these factors will be determined by the design and configuration of the pilot rotary APHs and associated equipment. However, some of the operational characteristics of full-scale units must be modified in smaller-scale equipment. The SCR rotary APH will be equipped with variable speed drives in order to vary rotational speed and, therefore, to properly match surface temperatures and temperature variations. Metal surface temperatures should be matched to within +/- 5°F. Temperature variations of APH baskets should match full-scale to within 1°F. Although it is desirable to maintain air inleakage below 10 percent of the flue gas flow, this has been deemed infeasable by APH vendors with pilot-scale APHs. The air inleakage may approach 20 percent for this pilot facility, but will be minimized as much as possible by varying air side flow and static pressure to not more than 1 inch of H_2O differential between the gas-side and air-side static pressure at the hot-end of the pilot-scale APH. This requires that the APH air flow be under induced draft.

The rotary APHs will be operated under these conditions while the associated large SCR reactor is in long-term testing. During this period, gas and air flows will be determined, as will inlet SO_3 and NH_3 concentrations, particulate mass loadings, and size distributions. The APH pressure drop and inlet and outlet temperatures will be monitored. Outlet O_2 will be measured to determine air leakage. Sootblowing will occur as required to maintain proper static pressure differentials across the APH. APH solid deposits will be sampled periodically to determine the nature of such deposits. The APH will be bypassed during parametric testing so that above design ammonia-to-NOx values, which will cause excessive ammonium bisulfate formation, will not contaminate long-term deposit formation in the APH.

The heat pipe APH has no corresponding gas/air flow and pressure drop concerns since it is a zero leakage device. It will be sized according to the heat transfer duties needed to simulate full-scale air preheater and monitored during long-term catalyst testing. Like the rotary units, it will be bypassed during parametric testing.

Startup and Shutdown Requirements

The SCR reactors require operation over a period of time prior to the loading of the catalyst, for proper seasoning of the ductwork and reactor walls. In addition, the SCR pilot facility commissioning tests will first be performed without catalysts, both with and without ammonia, followed by commission tests with and without ammonia.

Startup of the SCR reactors will require that the reactors are heated above the acid dew point, approximately 300°F, before introducing flue gas into the reactors. This will be accomplished by using ambient air purge heated by the electric flue gas heater for each reactor train. The ambient air inlet for each reactor train is located ahead of the flue gas heaters, and can also be used to purge the reactors during shutdown. Once the reactors are above the acid dew point, flue gas can then be introduced into the reactors, heating them to the desired operating temperature. To avoid ammonia-sulfur compound deposition, ammonia injection will only begin once the entire catalyst bed has reached the minimum operating temperature, based on SO_2, SO_3, and ammonia concentrations.

Although the flue gas temperatures are monitored, proper catalyst surface temperature is most important, for startup and shutdown, to identify whether the temperature is sufficient for operations with ammonia. Therefore, thermocouples will be mounted on the catalyst surface, on the inlet side of the first catalyst layer, and on the outlet surface of the last layer. Measurements will be made in the corners due to higher possible heat loss, as shown in Figure 2.3-11.

The SCR reactors also are purged, before shutting down, for the removal of ammonia. The air purge should occur above the condensation temperature of the ammonium sulfate compounds, approximately 450°F. Reactors also need to be purged when process upsets occur and the flue gas has to be diverted to the reactor bypass. This may be accomplished by using the air dilution system associated with ammonia injection, since the ammonia injection point is to be located between the reactor bypass take-off and the reactor inlet. Both low and high temperature alarms are located on the reactor inlets as well as the host boiler duct to prevent damage to the SCR catalysts. At high temperatures (>750°F), sintering of the catalyst can occur, which will greatly reduce the catalytic activity of the catalyst. At low temperatures, catalytic activity is reduced, thus causing a high ammonia slip, which can lead to high deposition of ammonium sulfate compounds in the downstream equipment and on the catalyst surface.

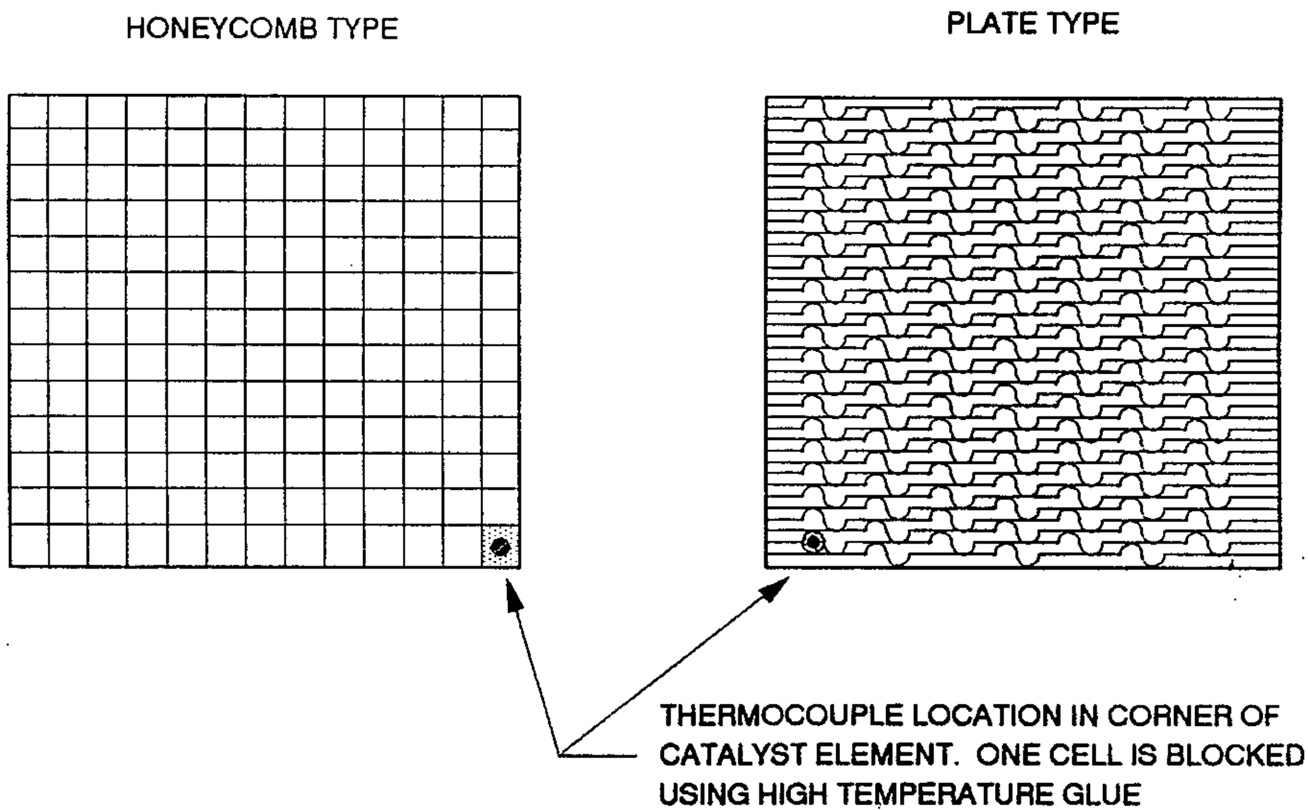


Figure 2.3-11. Thermo couple location in catalyst element.

Some of the preliminary concepts for start-up and routine shutdown procedures, handling process upsets, emergency shutdown, and changes to parametric testing are shown in Figures 2.3-12 through 2.3-21.

Economizer Bypass Vapor Phase — Trace-Metal Concentration Effects

Some SCR vendor development experience indicates that catalyst activity loss may vary with the extraction location of the flue gas from the host boiler. Flue gas extracted and treated immediately at the economizer wall can show higher trace metal concentrations and can lead to higher catalyst poisoning. Extracting and treating flue gas, after long duct runs with cooler gas temperatures, may allow vapor phase metal condensation. If extracted in this manner for a pilot plant, it is possible that the catalyst may not get exposed to the actual trace metal concentration that the catalyst would see on a commercial system. SCR developers operating a pilot plant with an extraction point, and reheat with electric heaters similar to our preliminary conceptual design, noticed relatively low catalyst activity loss. However, the commercial plant catalyst, located nearer the economizer and with an economizer bypass, was experiencing rapid catalyst activity loss. (See Figure 2.3-22.) They eventually added heat tracing to their pilot plant ductwork. This has been primarily noticed on wet bottom boilers with flyash recycle, which may allow rather high trace metal concentration build-up in the flue gas. Reheating the flue gas, once it has cooled, does not solve this problem. Once the trace metals deposit out on the ash, the temperature required to revaporize these compounds is much higher than the SCR operating temperature.

As a result of the above, it has been proposed to maintain the original main flue gas extraction point, while adding an economizer bypass line. (See Figure 2.3-23.) The economizer bypass would allow gas from the economizer/superheater region (See stream 2 on Figure 2.3-23; Optimum point to be determined.), to mix with the main gas slipstream being taken off between the economizer and hot-side ESP (stream 1) for the SCR pilot plant. The economizer bypass would be used only as needed to maintain a minimum temperature of 620°F for the total flue gas entering the SCR pilot plant

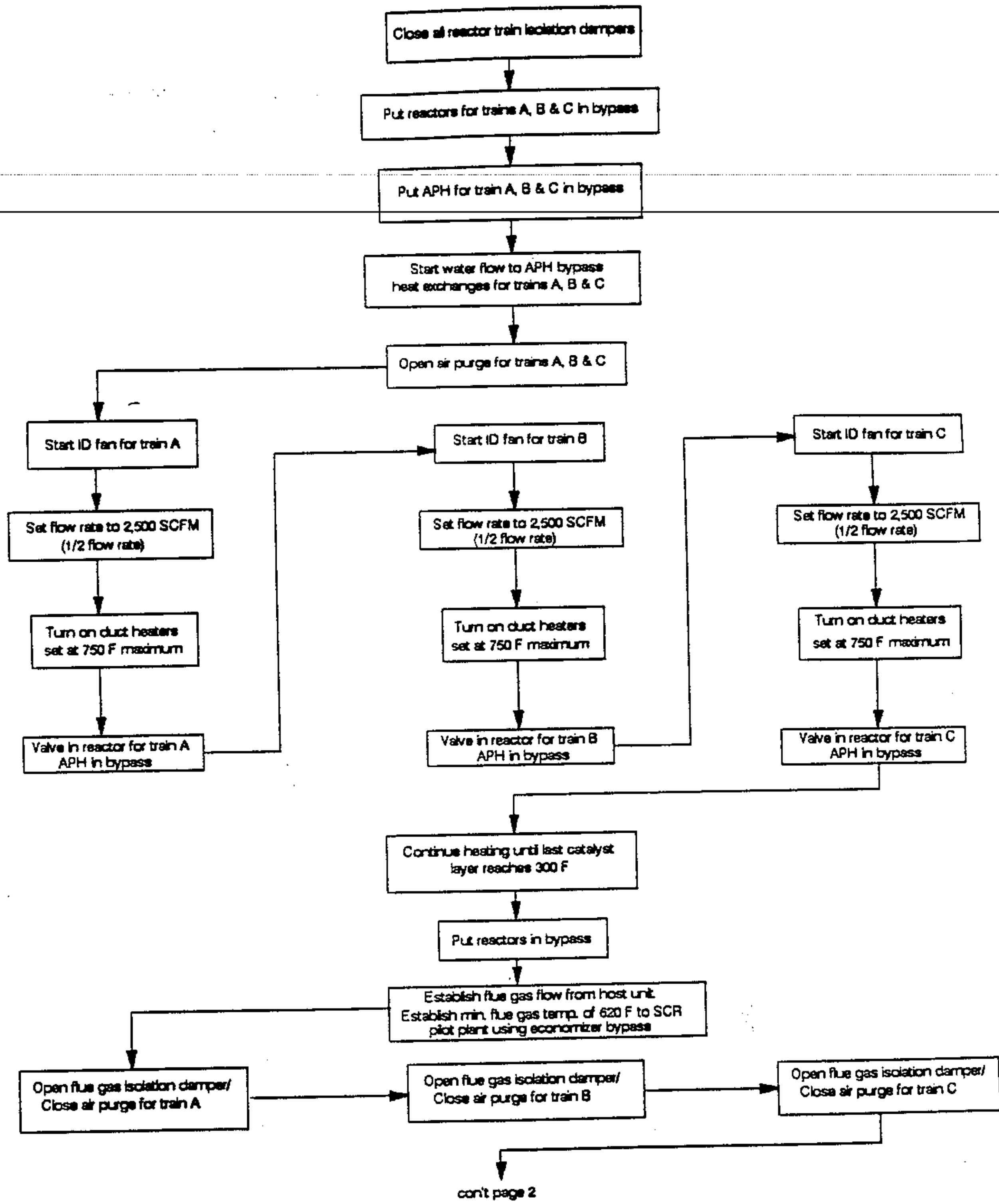


Figure 2.3-12. Startup of large SCR pilot reactors.

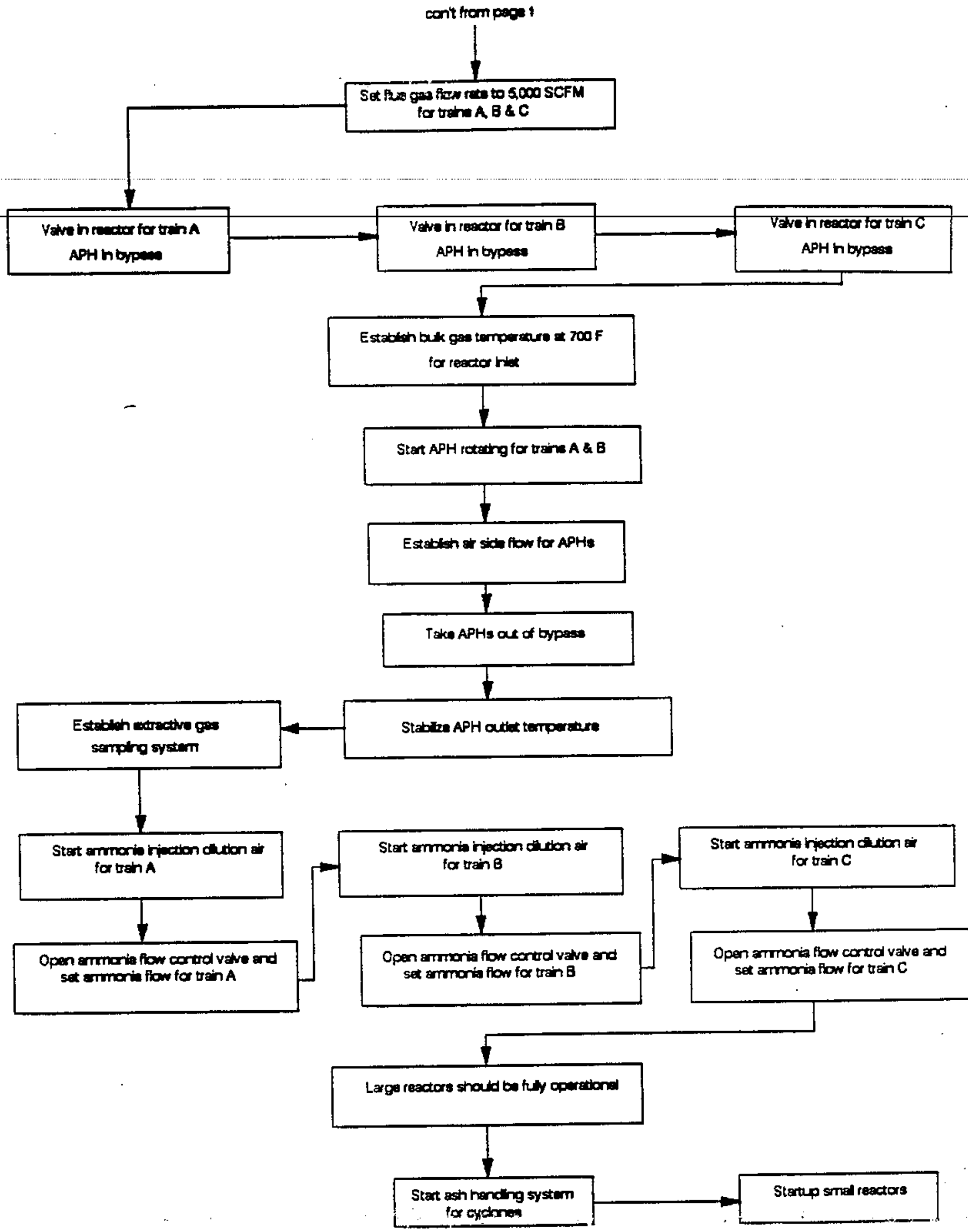


Figure 2.3-13. Startup of large SCR pilot reactors.

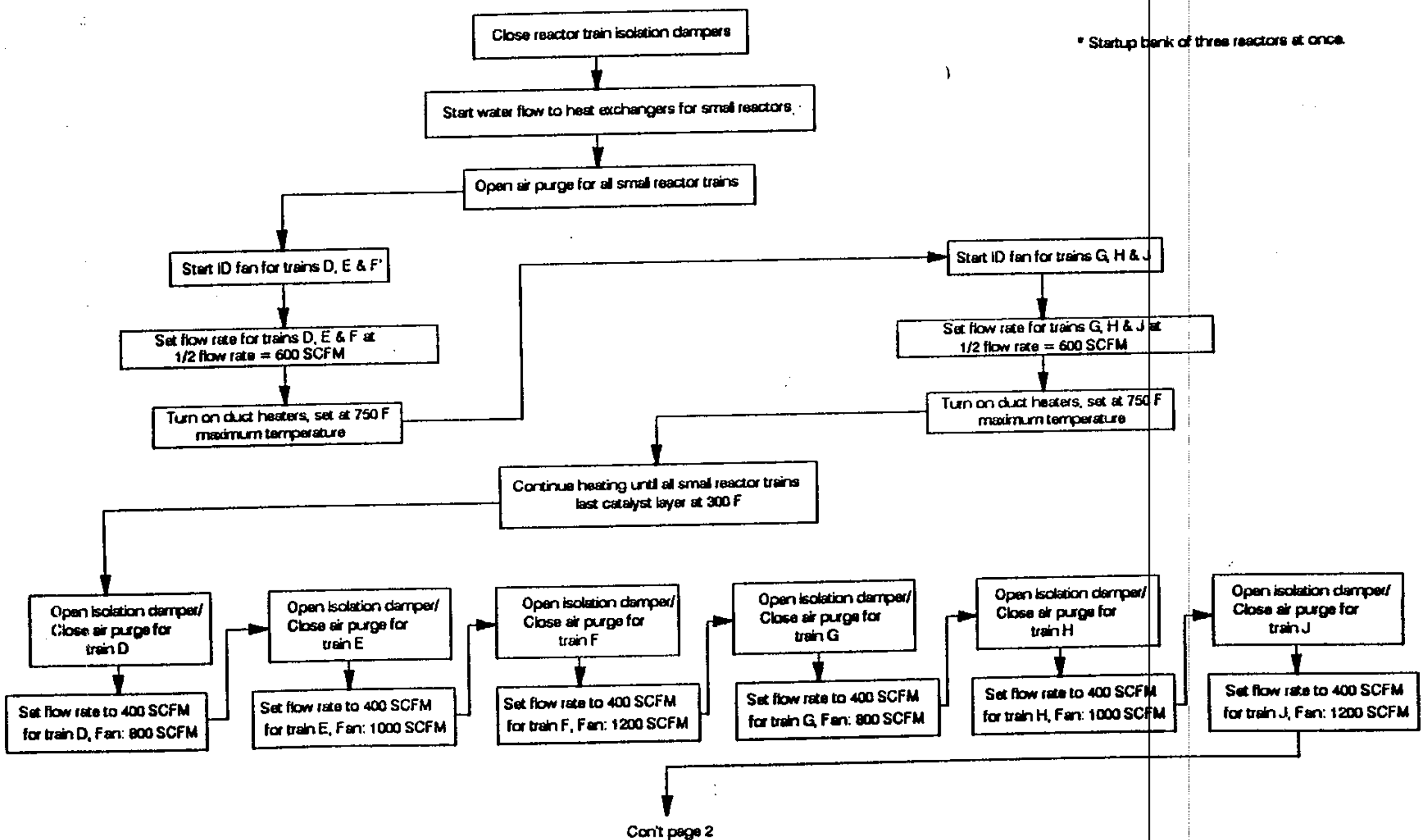


Figure 2.3-14. Startup of small SCR pilot reactors.

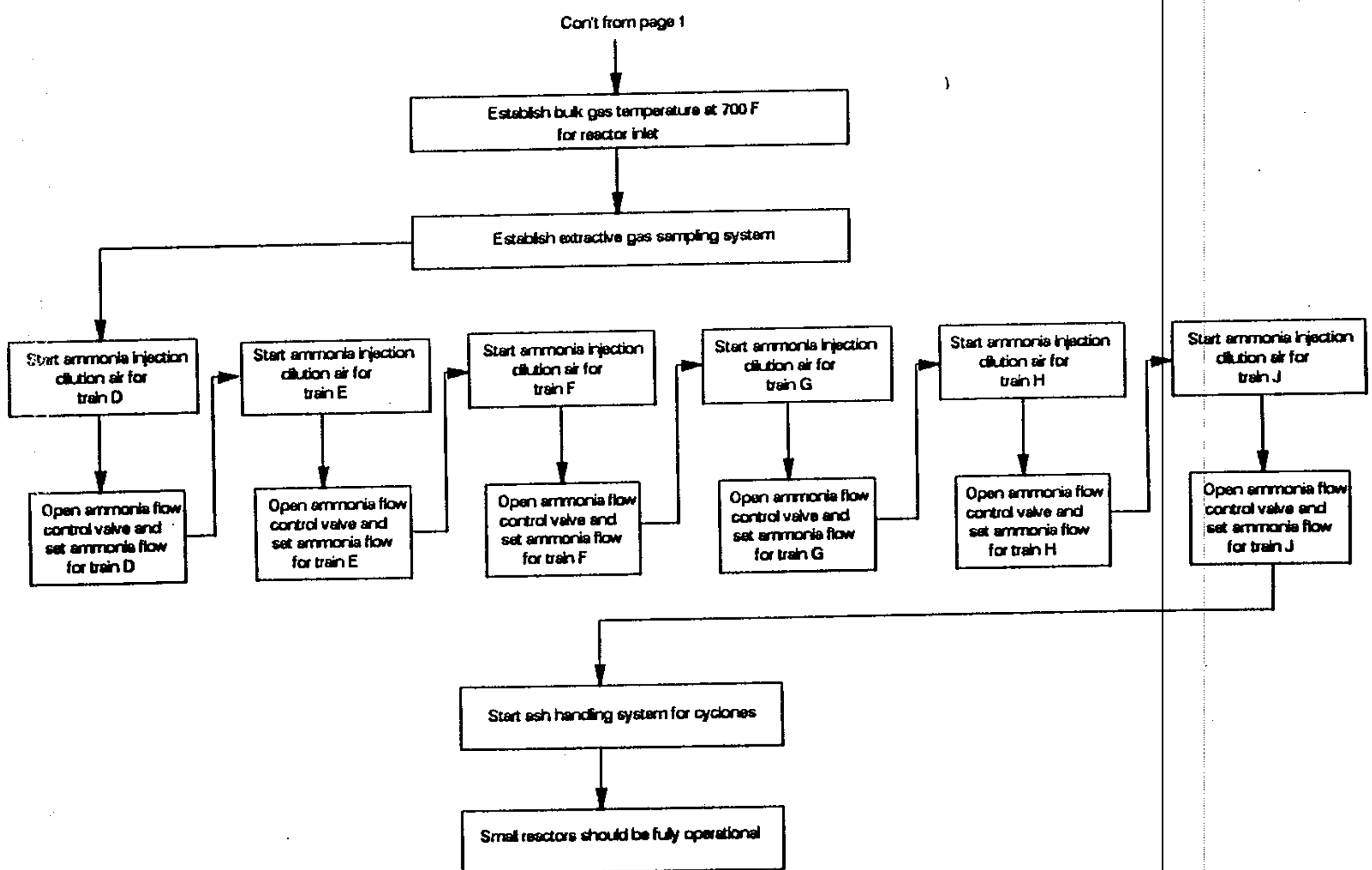


Figure 2.3-15. Startup of small SCR pilot reactors.

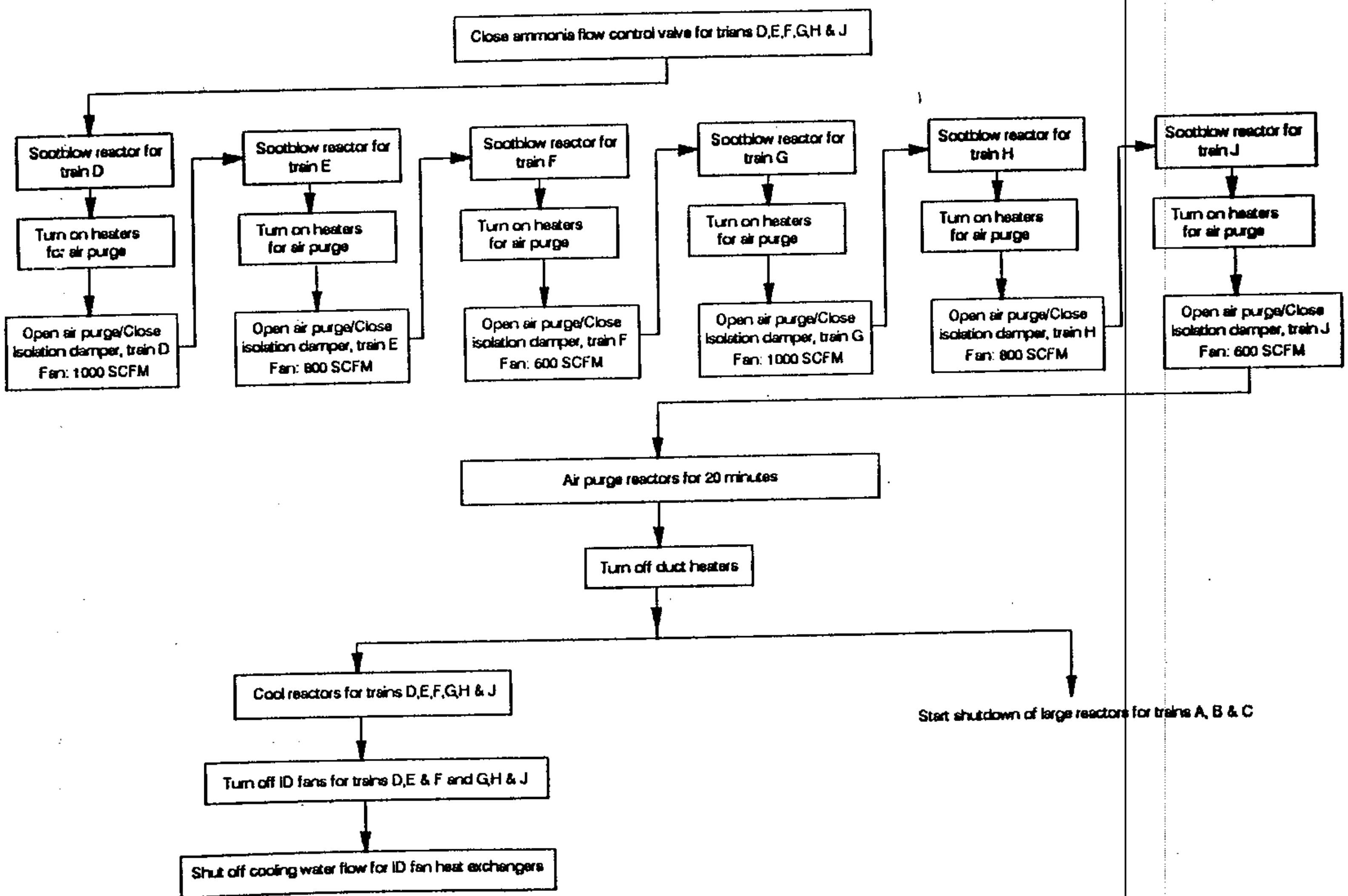


Figure 2.3-16. Routine shutdown for small SCR pilot reactors.

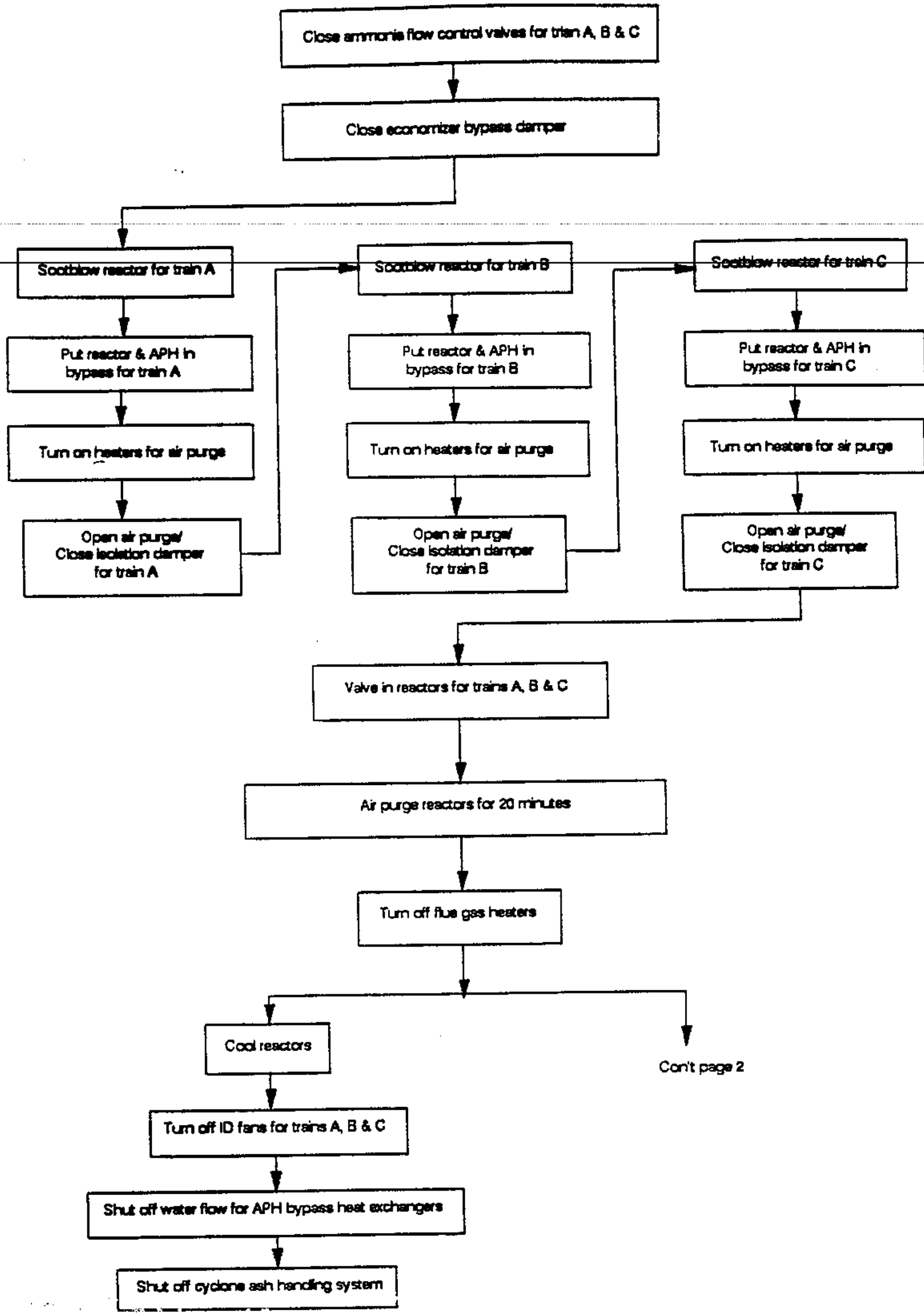


Figure 2.3-17. Routine shutdown for large SCR pilot reactors.

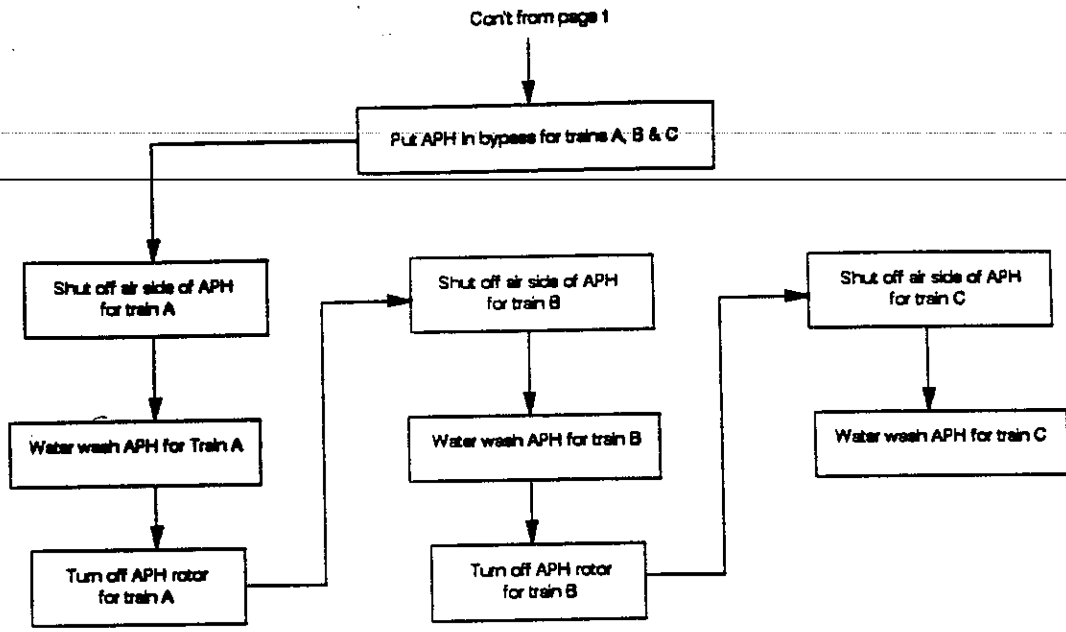


Figure 2.3-18. Routine shutdown for large SCR pilct reactors.

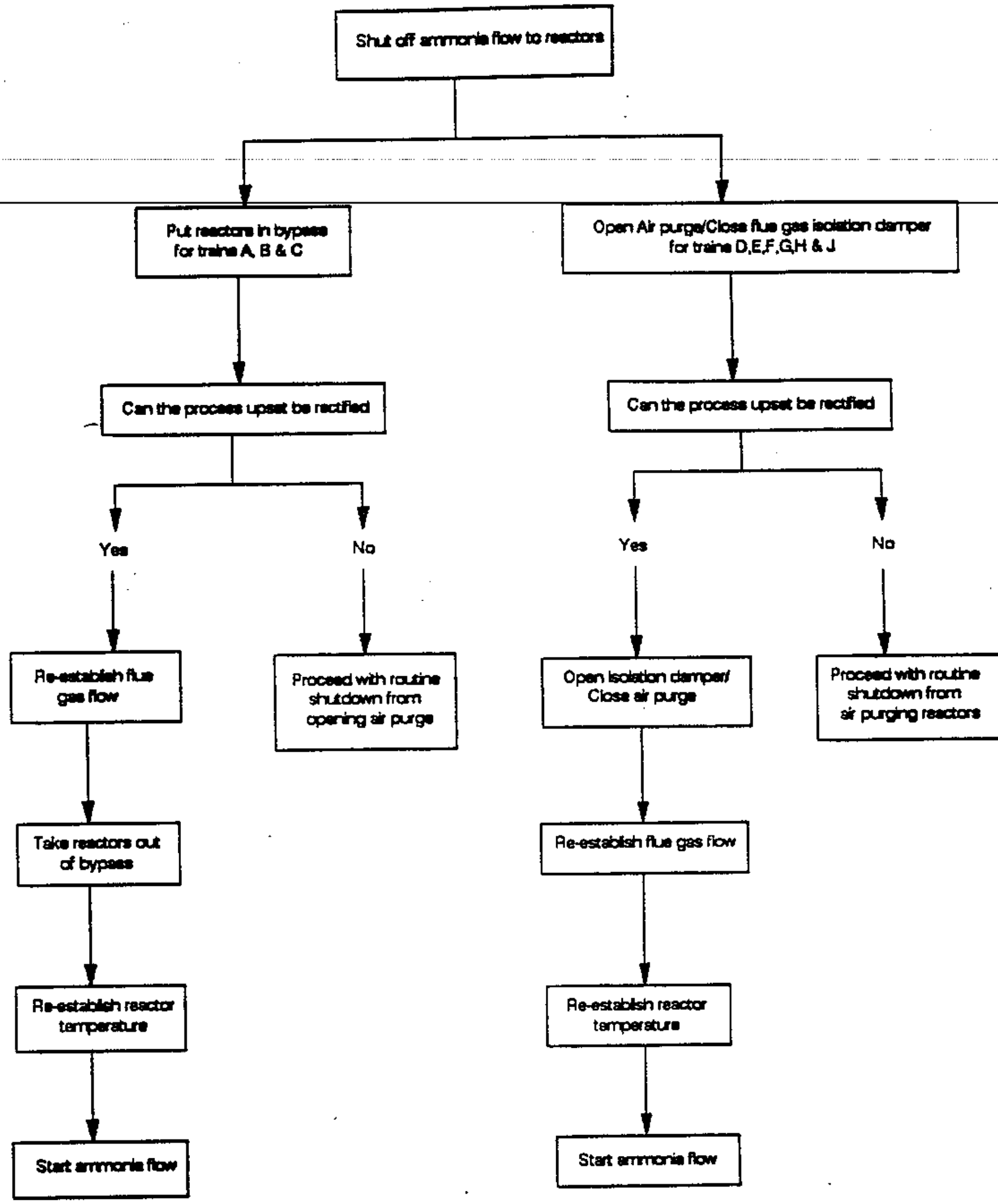


Figure 2.3-19. Process upsets for SCR pilot plant.

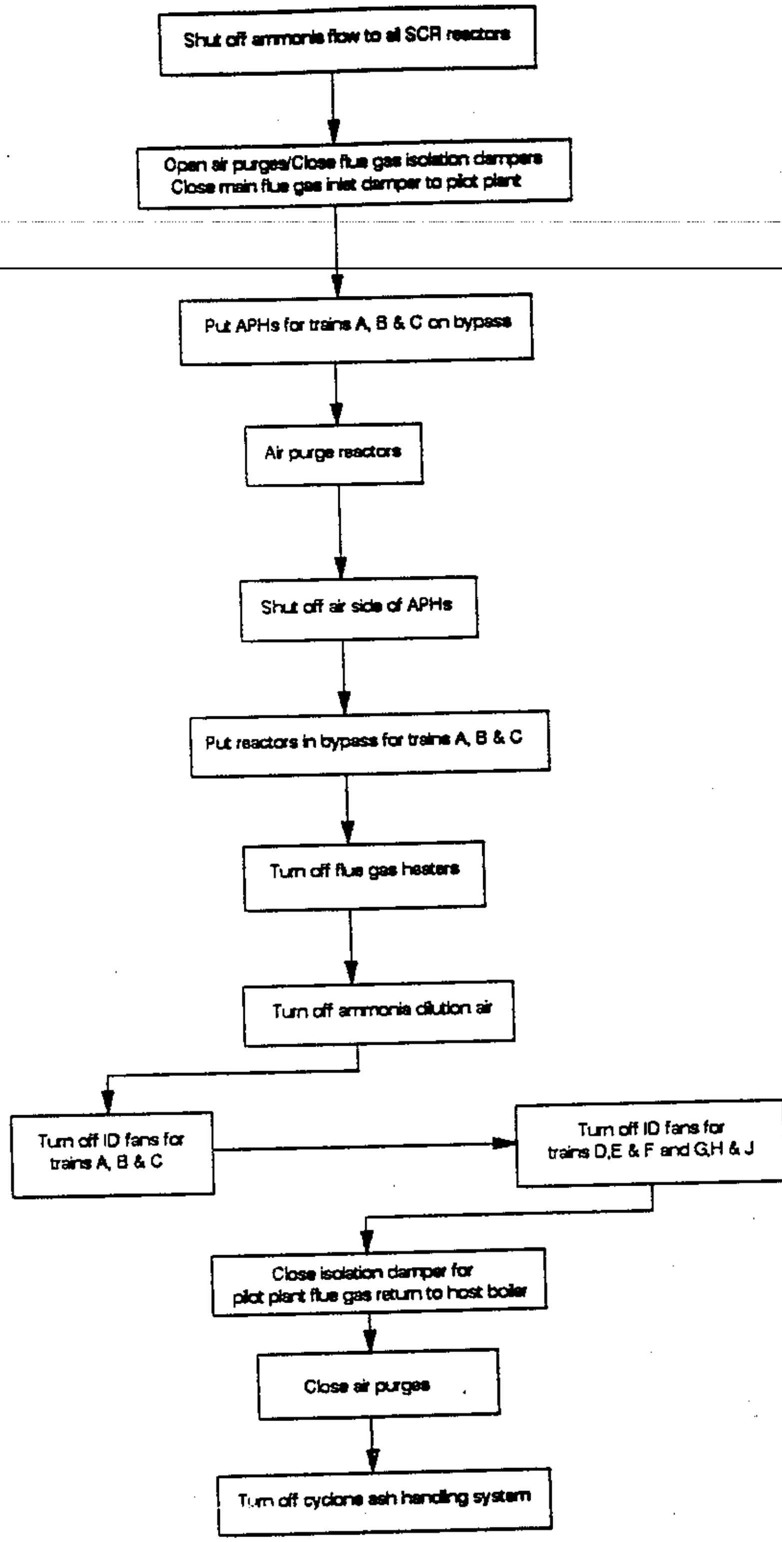


Figure 2.3-20. Emergency shutdown of SCR pilot plant.

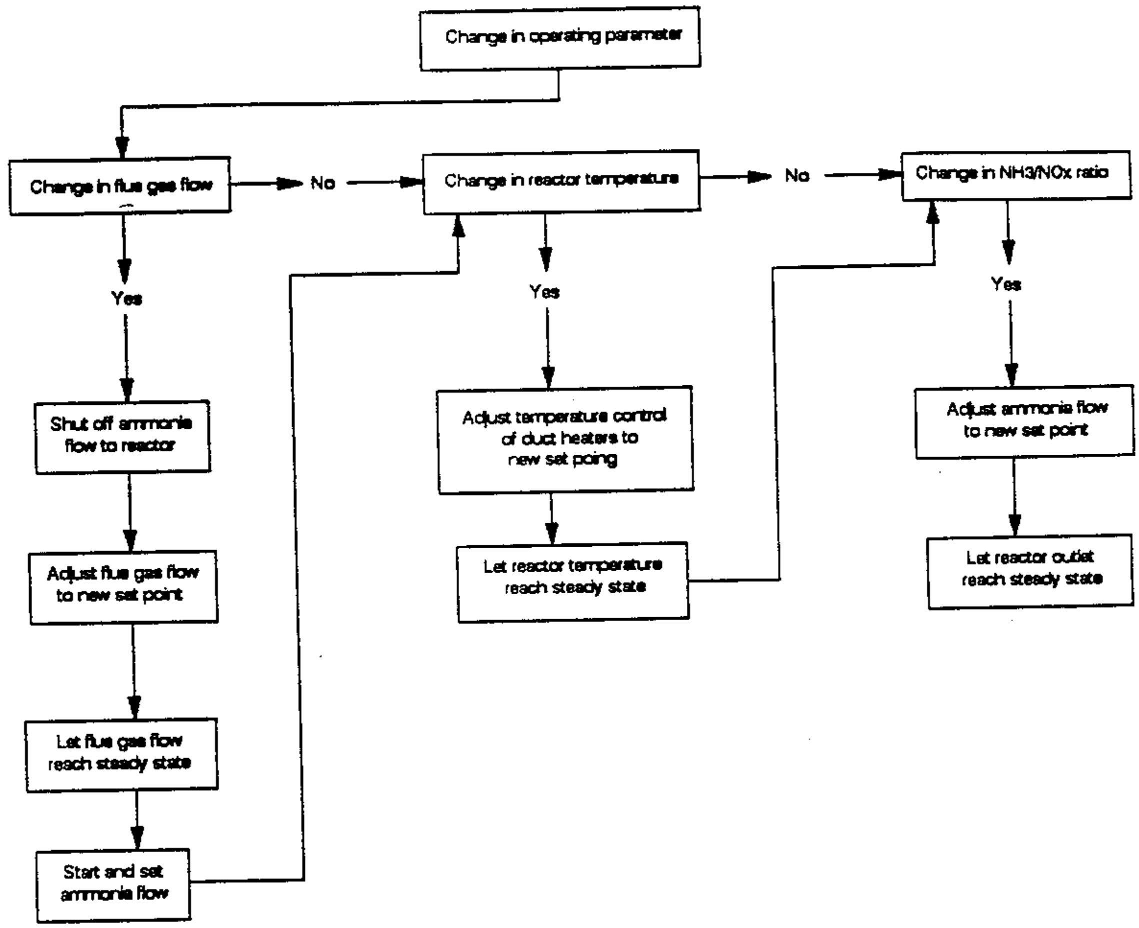


Figure 2.3-21. Parametric testing for SCR pilot plant.

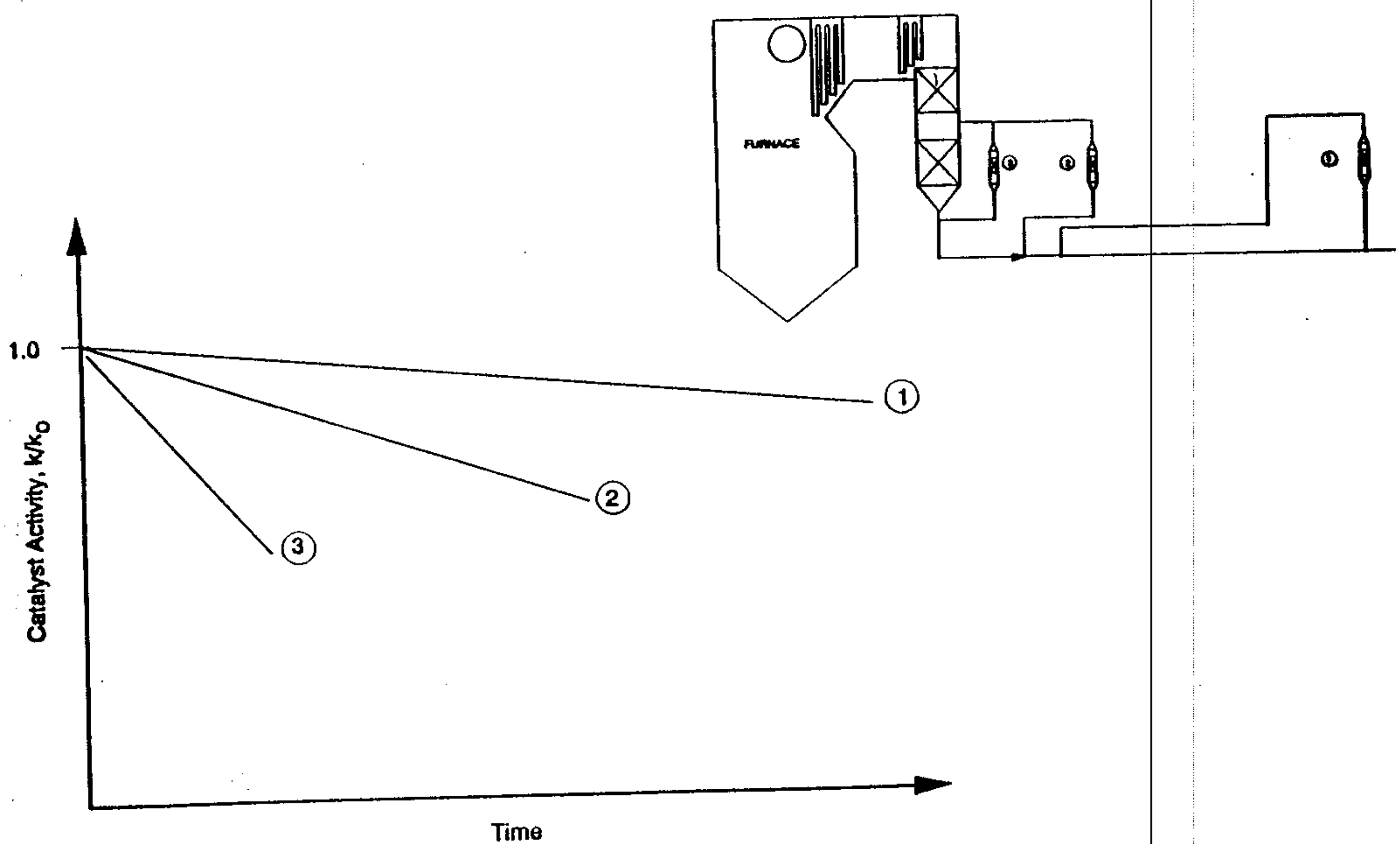


Figure 2.3-22. Catalysts activity loss.

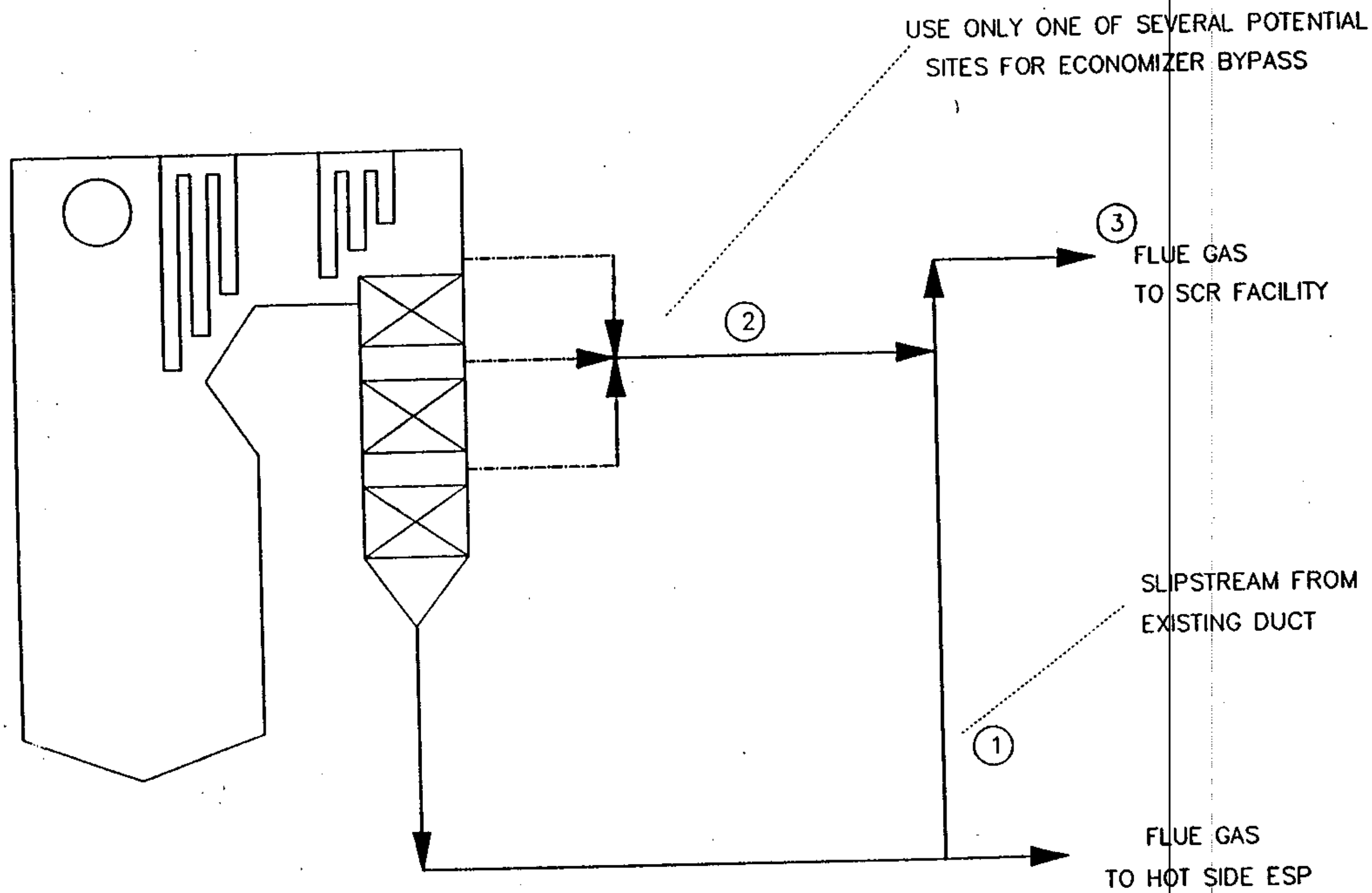


Figure 2.3-23. Schematic of potential economizer bypass for SCR facility at Plant Crist.

(stream 3), usually at low loads. At full load, the bypass would probably be closed. This mode of operation more closely resembles that of a commercial system, which normally has an economizer bypass, allowing the exposure of the catalysts to potential poisons, and therefore, more accurately reflecting the catalyst activity which would be experienced on a full-scale SCR system.

This economizer bypass concept is being evaluated for feasibility with Crist Unit 5 operations, with respect to existing tie-in locations, temperature profiles, and line sizing, which is anticipated to be small in comparison to the main extraction line.

In addition to the above bypass concept, the following alternatives may be implemented:

- Duplicate one of the test catalysts in a small reactor located at the economizer during the operation of the pilot plant — Gas passage through the reference reactor could be driven by differential pressure of the Unit 5 draft system, and NH_3 injection could use only bottled NH_3. The cross-sectional area of this reactor could be about the same as the smaller SCR pilot plant reactors, with a 2 x 2 catalyst element array (i.e., four elements of 150-mm side dimensions). One layer of catalyst would be sufficient. Such a system is represented in Figure 2.3-24.

- Install test coupons of catalyst samples to determine the potential severity of catalyst poisons — One set of catalyst coupons would be installed near the economizer region, and the other set would be located in the cooler duct region where pilot plant flue is extracted. One possibly may even be located in the pilot plant flue gas duct furthest downstream from the extraction point.

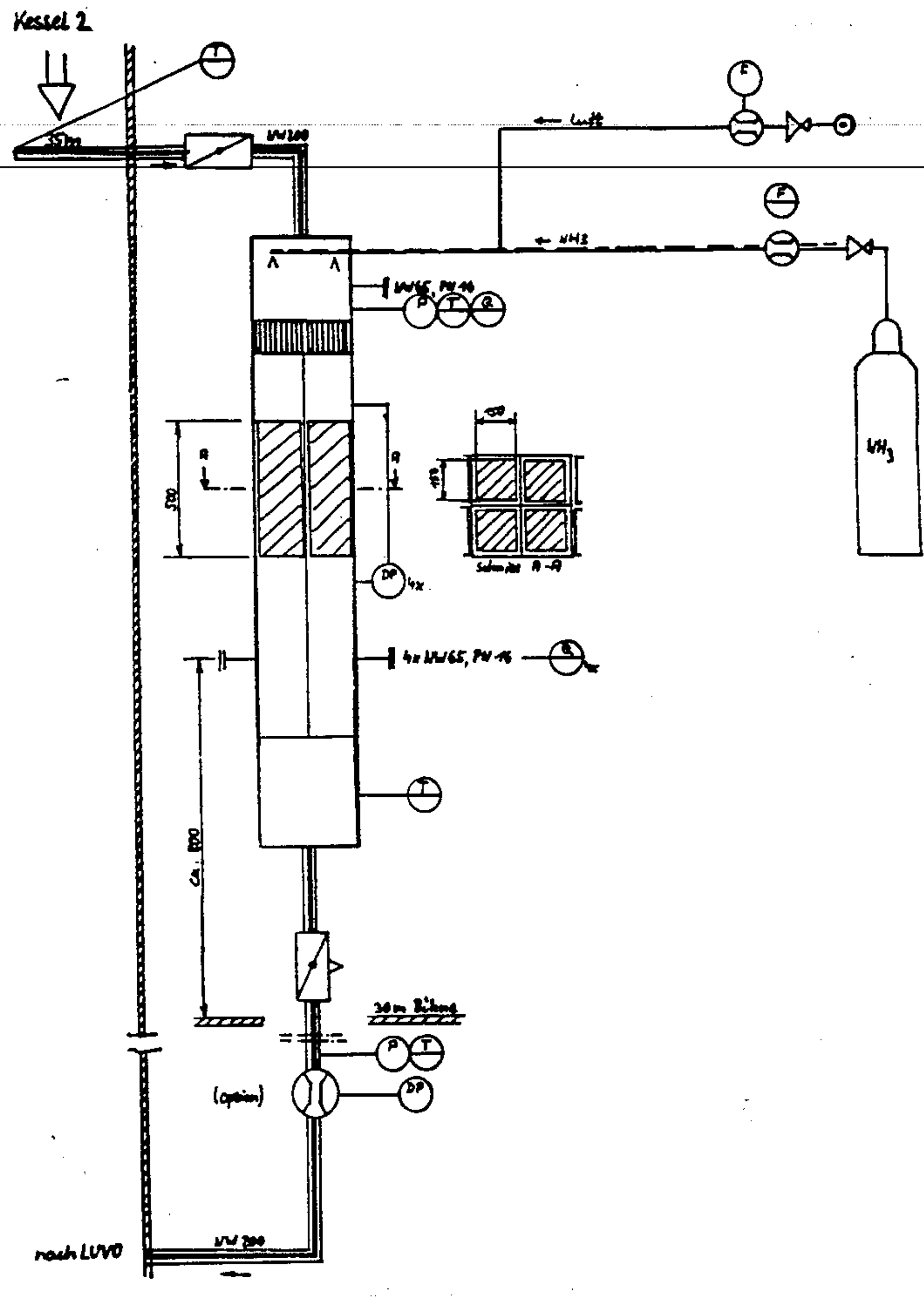


Figure 2.3-24. Reference reactor sketch.

- Gas sampling of trace metals — Sampling of ash concentration and gaseous concentrations of AS_2O_3, Hg, Pb, and Cd, as well as the concentration of these metals on the particulate, may be done. Simultaneous sampling should be done during commissioning at the following positions while Unit 5 is in steady state operation, and with no sootblowing in operation: extraction scoop; before the heater; and before each SCR reactor. This may be expensive, and sublimation of the gaseous trace elements could falsify results.

EXHIBIT 2.3-A

ESTIMATED PILOT PLANT EQUIPMENT WEIGHTS

Intracompany Memo Southern Company Services

DATE: September 19, 1990

RE: Estimated Pilot Plant Equipment Weights

FROM: Edward Healy

TO: Juan Blanco

Attached are my calculations estimating the SCR pilot plant weight. The estimate includes all large process equipment, piping, and insulation that I can think of at this time. The summary shown on page 19 indicates a total pilot plant weight of 638,000 lbs. This total includes a 15% margin for flanges, instrumentation, contingency, etc.

The estimate <u>does</u> <u>not</u> include structural steel, grating, checker plate, area lighting fixtures, bracing, and other structural components. The weights and appropriate margin for these components are probably better estimated by you. Also not included is the bulk ammonia storage tank(s) and ammonia dilution skid weight. This equipment is not fully defined at this time and will be located somewhat remotely from the pilot plant structure. Also, I suspect that the storage tank and dilution skid will require only a pad foundation.

I hope this provides you enough information to get started on your preliminary design. I will continue to forward pertinent information as it becomes available. If you have any questions, please feel free to call me on extension 5212.

SCR08.doc
ech

cc: Ray Bailey
Kerry Bowers
Rod Sears
Rick Ranhotra
Zack Looney
Gray Murray

Design Calculations **Southern Company Services**

Project	Prepared By	Date
DOE SCR PROJECT	ECG	7/19/93
Subject/Title	**Reviewed By**	**Date**
ESTIMATED WEIGHTS		
	Calculation Number	**Sheet** 1 of

PILOT PLANT INLET HEADER

ASSUME 150' OF 42"Ø STD WEIGHT CARBON STEEL PIPE WITH 6" THK CALCIUM SILICATE INSULATION

REFERENCE 1: [GRINNELL PIPE HANGER DESIGN + ENGINEERING MANUAL REVISED 1979]

FROM GRINNELL P 49

PIPE WEIGHT = 167 lb/FT
INSULATION WEIGHT = 73 lb/FT
TOTAL WEIGHT = 240 lb/FT

∴ INLET HEADER WEIGHT = $\frac{150\ FT}{} \cdot \frac{240\ lb}{FT}$ = **36,000 lb** ←

FLUE GAS ISOLATION DAMPER

ASSUME 42"Ø ALLIS-CHALMERS BUTTERFLY VALVE MODEL 50-2 WITH ACTUATOR

FROM A-C CATALOG VA1.3-, P102

VALVE WEIGHT = 3000 lb
ACTUATOR WEIGHT = 300 lb
TOTAL WEIGHT = 3300 lb

∴ $\frac{3300\ lb}{VALVE} \cdot \frac{1\ VALVE}{}$ = **3300 lb** ←

Form No. 9-324A

Design Calculations   Southern Company Services

Project	Prepared By	Date
DOE SCR PROJECT	ECH	9/18/90
Subject/Title	Reviewed By	Date
ESTIMATED WEIGHT		
	Calculation Number	Sheet
	90206PE-3	2 of

LARGE REACTOR TRAINS (PER TRAIN) X3 FOR TOTAL

HEADER LATERALS

ASSUME 42"Ø STD WEIGHT TEE

FROM GRINNELL p 49, TEE WEIGHT = 1870 lb ←

ISOLATION DAMPER

ASSUME 24"Ø ALLIS-CHALMERS BUTTERFLY VALVE MODEL 50FR WITH ACTUATOR

FROM A-C CATALOG VA1.2a p102

VALVE WEIGHT = 890 lb
ACTUATOR WEIGHT = 300 lb
TOTAL WEIGHT = 1190 lb

TOTAL OF 8 DAMPERS (VALVES) FOR RXR TRAIN

∴ 1190 lb | 8 = 9520 lb ←

ELECTRIC HEATER

ASSUME 5 x 64 kW WATLOW FIREBAR® FLANGED ELECTRIC IMMERSION HEATER.

FROM WATLOW CATALOG PC8889, P 165

HEATER WEIGHT (6" FLANGE) = 95 lb EACH

Form No. 9-324A

$\therefore$ HEATER WEIGHT = $\frac{95 \text{ lb}}{\text{HTR}} \Big| 5 \text{ HEATERS}$ = 475 lb ←

VENTURI

ASSUME 24"Ø SCH 160 CARBON STEEL PIPE w/ 4½" HTE INSULATION

FROM GRINNELL, p 42

PIPE WEIGHT = 542 lb/FT
INSULATION WEIGHT = 33 lb/FT
TOTAL WEIGHT = 575 lb/FT

ASSUME VENTURI LENGTH OF 4 FT

$\therefore$ $\frac{575 \text{ lb}}{\text{FT}} \Big| 4 \text{ FT}$ = 2300 lb ←

RXR INLET DUCTWORK

ASSUME 50 FT OF 24"Ø STD WEIGHT PIPE WITH 4½" INSULATION

FROM GRINNELL p 42

PIPE WEIGHT = 95 lb/FT
INSULATION WEIGHT = 33 lb/FT
TOTAL WEIGHT = 128 lb/FT

$\therefore$ RXR INLET DUCTWORK = $50 \text{ FT} \Big| \frac{128 \text{ lb}}{\text{FT}}$ = 6400 lb ←

Design Calculations **Southern Company Services**

Project: DOE SCR PROJECT	Prepared By: ECA	Date: 9/19/97
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: 90206 PE-3	Sheet 4 of

AIR PURGE FITTINGS

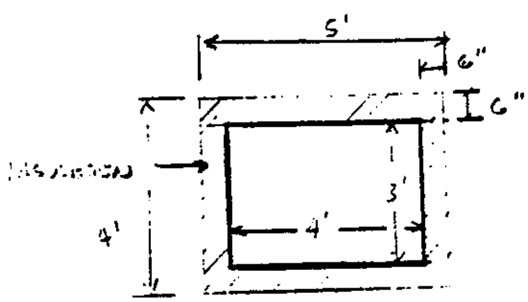
ASSUME 24"Ø STD WEIGHT TEE

FROM GRINNELL, P 42 TEE WEIGHT = 544 lb

∴ AIR PURGE CONNECTION = 544 lb | 1 = **544 lb** ←

REACTOR

ASSUME RXR DIMENSIONS OF 3'×4'×50' (INCLUDES TRANSITION)
1/4" CARBON STEEL PLATE w/ 6" THK MINERAL WOOL INSULATION.



PER WILLARD BROOKS

INSULATION	8 lb/FT³
LAGGING	2 lb/FT²

PER JOHN BURKO

1/4" THK PLATE - 490 lb/FT³
ADD 15% FOR INTERNAL SUPPORT

STEEL VOLUME: $((2\times4')+(2+3'))\times 50\,FT \times \left(\frac{.25}{12}\right) = 15\,FT^3$

RXR WEIGHT = $15\,FT^3 \mid \frac{490\,lb}{FT^3} \mid 1.15$ = **8453 lb**

INSULATION VOLUME. $\left[\left(2\times5'\times\frac{6}{12}\right)+\left(2\times3'\times\frac{6}{12}\right)\right]\times 50\,FT = 400\,FT^3$

OUTSIDE SURFACE AREA: $((2\times5')+(2\times4'))\times 50\,FT = 900\,FT^2$

Design Calculations Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECA	Date: 7/12/9?
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: SD206PE-?	Sheet 5 of

LAGGING WEIGHT : $\frac{900\ FT^2 \mid 2\ lb}{\mid FT^2}$ = 1800 lb

INSULATION WEIGHT : $\frac{400\ FT^3 \mid 8\ lb}{\mid FT^3}$ = 3200 lb

TOTAL INSULATION WEIGHT 5000 lb

CATALYST WEIGHT

ASSUME CATALYST DIMENSIONS TO BE 3' x 4' x 3' DEEP (i.e. ~1 m) WITH DENSITY OF 50 lb/FT³. ASSUME CAPABILITY FOR 4 CATALYST LAYERS PER RXR (ONLY 3 ARE REQD AT THIS TIME). ASSUME CATALYST BASKET WEIGHT OF 200 lb.

∴ CATALYST WEIGHT PER LAYER = $\frac{3\ FT \mid 4\ FT \mid 3\ FT \mid 50\ lb}{\mid \mid \mid FT^3}$ + 200 lb = 2000 lb/LAYER

TOTAL CATALYST WEIGHT = $\frac{4\ LAYERS \mid 2000\ lb}{\mid LAYER}$ = 8000 lb

ROTARY AIR PREHEATERS

2 OF 3 RXR TRAINS WILL HAVE ROTARY AIR PREHEATERS. FROM CE PROPOSAL 3DQU-049-B, WEIGHT FOR EACH ROTARY IS :

27,100 lb EACH

Form No. 9-324A

Design Calculations Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECH	Date: 9/19/90
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: 90206 PE-3	Sheet: 6 of

HEAT PIPE APH

1 OF 3 RXR TRAINS WILL HAVE HEAT PIPE. FROM CE PROPOSAL 8DQU-C49-C, WEIGHT OF HEAT PIPE IS:

45,000 lb ←

REACTOR BYPASS DUCTWORK

ASSUME 75 FT OF 24"Ø STD WEIGHT PIPE w/ 4½" INSULATION

FROM GRINNELL, p42

PIPE WEIGHT = 95 lb/FT
INSULATION WEIGHT = 33 lb/FT
TOTAL 128 lb/FT

∴ BYPASS DUCTWORK: $\frac{75\ FT \mid 128\ lb}{\mid FT}$ = 9600 lb ←

BYPASS HEAT EXCHANGER

NO WEIGHT INFO AVAILABLE. THEREFORE, ASSUME 24"Ø STD WT PIPE FILLED WITH WATER.

FROM GRINNELL p 42,

PIPE WEIGHT = 95 lb/FT
INSULATION WEIGHT = 33 lb/FT
WATER WEIGHT = 184 lb/FT
TOTAL WEIGHT = 312 lb/FT

Form No. 9-324A

Design Calculations | Southern Company Services

Project	Prepared By	Date
DOE SCR PROJECT	ECK	9/13/03
Subject/Title	**Reviewed By**	**Date**
ESTIMATED WEIGHTS		
	Calculation Number	**Sheet**
	90206 FT-?	7 of

ASSUME HX LENGTH OF 5'-0"

$\therefore$ HX WEIGHT = $\frac{5\,FT \mid 312\,lb}{FT}$ = **1560 lb** ←

CYCLONES

FROM BARRON PROPOSAL CL-JAL-16892, CYCLONE WEIGHT IS:

3000 lb ←

AIR HEATER FANS

PER STEVE RAINOR

FAN WEIGHT	=	800 lb
BASE WEIGHT	=	500 lb
MOTOR WEIGHT	=	1700 lb
TOTAL		3000 lb

$\therefore$ EACH AIR FAN WEIGHT = **3000 lb** ←

(REFERENCE PAGE 20)

Form No. 9-324A

Design Calculations | Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECA	Date: 9/18/90
Subject/Title: ESTIMATED WEIGHT	Reviewed By:	Date:
	Calculation Number: 90206PE-3	Sheet: 3 of

RXR OUTLET DUCTWORK

ASSUME 50 FT OF 24"ϕ STD WEIGHT PIPE w/ 4 1/2" INSULATION

(SAME AS RXR INLET DUCT) = 6400 lb ←

AIR DUCTWORK

ASSUME 50 FT OF 30"ϕ STD WEIGHT PIPE w/ 6" INSULATION

FROM GRINNELL, P 45

PIPE WEIGHT = 119 lb/FT
INSULATION WEIGHT = 55 lb/FT
TOTAL WEIGHT 174 lb/FT

∴ AIR DUCTWORK WEIGHT = $\frac{50 \text{ FT} \mid 174 \text{ lb}}{\mid \text{FT}}$ = 8700 lb ←

FLUE GAS FANS

PER STEVE MINOR

FAN WEIGHT = 600 lb
BASE WEIGHT = 500 lb
MOTOR WEIGHT = 2450 lb
TOTAL = 3550 lb

∴ EACH FAN WEIGHT = 3550 lb ←

(REFERENCE PAGE 20)

Form No. 9-324A

Design Calculations Southern Company Services

Project	Prepared By	Date
DOE SCR PROJECT	E-A	9/18/92
Subject/Title	**Reviewed By**	**Date**
ESTIMATED WEIGHTS		
	Calculation Number	**Sheet**
	9020?-E-3	9 of

LARGE RXR TRAIN SUMMARY

	RXR A	RXR B	RXR C	TOTAL
HEADER LATERALS	1870	1870	1870	5610
ISOLATION DAMPERS	9520	9520	9520	28560
ELECTRIC HEATER	475	475	475	1425
VENTURI	2300	2300	2300	6900
INLET DUCTWORK	6400	6400	6400	19,200
AIR PURGE CONNECTION	544	544	544	1632
REACTOR	8453	8453	8453	25359
INSULATION (RXR)	5000	5000	5000	15000
CATALYST	8000	8000	8000	24000
AIR HEATERS	27100	27100	45000	99,200
BYPASS DUCTWORK	9600	9600	9600	28800
BYPASS HEAT EXCHANGER	1560	1560	1560	4680
CYCLONES	3000	3000	3000	9000
AIR HEATER FANS	3000	3000	3000	9000
RXR OUTLET DUCTWORK	6400	6400	6400	19200
AIR DUCTWORK	8700	8700	8700	26100
FLUE GAS FANS	3550	3550	3550	10650
	105472	105472	123372	334316

Design Calculations Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECA	Date: 9/18/90
	Reviewed By:	Date:
Subject/Title: ESTIMATED WEIGHTS	Calculation Number: 90206PE-3	Sheet: 10 of

SMALL REACTOR TRAINS (PER TRAIN) x 6 FOR TOTAL

HEADER LATERALS

ASSUME 8"ϕ STD WEIGHT TEE

FROM GRINNELL, P 34 TEE WEIGHT = 60 lb ←

ISOLATION DAMPERS

ASSUME 8"ϕ ALLIS-CHALMERS BUTTERFLY VALVE MODEL 150 FR WITH ACTUATOR

FROM A-C CATALOG VA 1.1/9, P102

VALVE WEIGHT = 70 lbs
ACTUATOR WEIGHT = 55 lbs
TOTAL WEIGHT 125 lbs

TOTAL OF 2 DAMPERS PER RX TRAIN

∴ 125 lbs | 2 ≅ 250 lbs ←

ELECTRIC HEATERS

ASSUME 1 x 20 KW WATLOW FIREBAR® FLANGED ELECTRIC IMMERSION HEATER.

FROM WATLOW CATALOG PC 8889, p165

Form No. 9-324A

Design Calculations Southern Company Services

Project DOE SCR PROJECT	Prepared By ECH	Date 9/18/90
Subject/Title ESTIMATED WEIGHTS	Reviewed By	Date
	Calculation Number 90206PE-3	Sheet 11 of

HEATER WEIGHT = 35 lbs EACH

VENTURI

ASSUME 8"Ø SCH 160 CS PIPE w/ 4½" THK INSULATION

FROM GRINNELL p 34

PIPE WEIGHT = 75 lb/FT
INSULATION WEIGHT = 16 lb/FT
TOTAL WEIGHT 91 lb/FT

ASSUME VENTURI LENGTH OF 2 FT

∴ VENTURI WEIGHT = 2 FT | 91 lb / FT = 182 lb

RxR INLET DUCTWORK

ASSUME 50 FT of 8"Ø CS STD WEIGHT PIPE w/ 4½" INSULATION

FROM GRINNELL, p 34

PIPE WEIGHT = 29 lb/FT
INSULATION WEIGHT = 16 lb/FT
TOTAL WEIGHT = 45 lb/FT

∴ RxR INLET DUCTWORK = 50 FT | 45 lb / FT = 2250 lb

Design Calculations — Southern Company Services

Project	Prepared By	Date
DOE SCR PROJECT	ECA	9/18/90
Subject/Title	**Reviewed By**	**Date**
ESTIMATED WEIGHTS		
	Calculation Number	**Sheet**
	90206PE-3	12 of

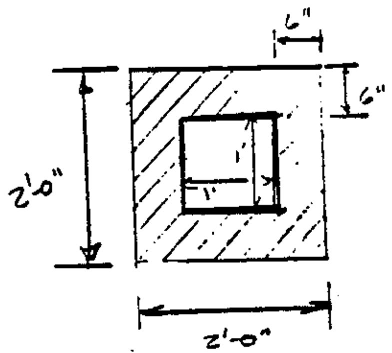
AIR PURGE FITTINGS

ASSUME 8"ϕ STD WEIGHT TEE

FROM GRINNELL, P 34 TEE WEIGHT = 60 lb

REACTOR

ASSUME REACTOR DIMENSIONS OF 1' x 1' x 50' (INCLUDES TRANSITION) 1/4" CARBON STEEL PLATE w/ 6" MINERAL WOOL INSULATION.



PER WILLARD BROOKS

INSULATION 8 lb/FT^3
LAGGING 2 lb/FT^2

PER JUAN BLANCO

1/4" THK PLATE @ 490 lb/FT^3
ADD 15% FOR INTERNAL SUPPORT

STEEL VOLUME: $((2 \times 1') + (2 \times 1')) \times 50' \times (\frac{.25}{12}) = 4.2 \text{ FT}^3$

RXR WEIGHT = $\frac{4.2 \text{ FT}^3 \mid 490 \text{ lb} \mid 1.15}{\mid \text{FT}^3 \mid}$ = 2367 lb

INSULATION VOLUME: $[(2 \times 2' \times \frac{6}{12}) + (2 \times 1' \times \frac{6}{12})] \times 50 \text{ FT} = 150 \text{ FT}^3$

OUTSIDE SURFACE AREA: $(4 \times 2') \times 50' = 400 \text{ FT}^2$

Form No. 9-324A

Design Calculations Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECA	Date: 9/18/93
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: 90206PE-2	Sheet: 13 of

LAGGING WEIGHT = $\frac{400\ FT^2 \mid 2\ lb}{\mid FT^2}$ = 800 lb

INSULATION WEIGHT = $\frac{150\ FT^3 \mid 8\ lb}{\mid FT^3}$ = 1200 lb

TOTAL INSULATION WEIGHT = **2000 lb**

CATALYST WEIGHT

ASSUME CATALYST DIMENSIONS TO BE 1' x 1' x 3' DEEP WITH DENSITY OF 50 lb/FT³. ASSUME 1 CATALYST FOR 4 CATALYST LEVELS. ASSUME CATALYST BASKET WEIGHT OF 50 lb.

∴ CATALYST WEIGHT = $\frac{1\ FT \mid 1\ FT \mid 3\ FT \mid 50\ lb}{\mid \mid \mid FT^3}$ + 50 lb = 200 lb/LAYER

TOTAL CATALYST WEIGHT = $\frac{4\ LAYERS \mid 200\ lb}{\mid LAYER}$ = **800 lb**

CYCLONE

FROM BARRON PROPOSAL CL-JAK-16892, CYCLONE WEIGHT IS

450 lbs

Design Calculations Southern Company Services

Project	Prepared By	Date
DOE SCR PROJECT	ECA	9/18/90
Subject/Title	**Reviewed By**	**Date**
ESTIMATED WEIGHT		
	Calculation Number	**Sheet**
	90206PE-3	14 of

SMALL RXR HEAT EXCHANGER

ASSUMING APPROXIMATELY SAME WEIGHT AS LARGE RXR BYPASS HX.

1560 lb ←

RXR OUTLET DUCTWORK

ASSUME 50 FT OF 8" Ø STD WEIGHT CS PIPE w/ 4½" INSULATION.

(SAME AS RXR INLET DUCTWORK) = 2250 lb ←

FLUE GAS FANS

PER STEVE MINOR

FAN WEIGHT	950 lb
BASE WEIGHT	500 lb
MOTOR WEIGHT	2600 lb
TOTAL	4050 lb

∴ EACH FAN TOTAL WEIGHT = 4050 lb ←

(REFERENCE PAGE 20)

Form No. 9-324A

Design Calculations — Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECA — Date: 9/18/90
Subject/Title: ESTIMATED WEIGHTS	Reviewed By: — Date:
	Calculation Number: 9020617E-3 — Sheet 15 of

SMALL RXR TRAIN SUMMARY

	RXR D	RXR E	RXR F	RXR G	RXR H	RXR I	TOTAL
HEADER LADDERS	60	60	60	60	60	60	360
ISOLATION DAMPERS	250	250	250	250	250	250	1500
ELECTRIC HTR	35	35	35	35	35	35	210
VENTURI	182	182	182	182	182	182	1092
INLET DUCTWORK	2250	2250	2250	2250	2250	2250	13,500
AIR PURGE FITTING	60	60	60	60	60	60	360
REACTOR	2367	2367	2367	2367	2367	2367	14202
RXR INSULATION	2000	2000	2000	2000	2000	2000	12000
CATALYST	800	800	800	800	800	800	4800
CYCLONE	450	450	450	450	450	—	2250
OUTLET DUCTWORK	2250	2250	2250	2250	2250	2250	13500
	10704	10704	10704	10704	10704	10254	
HEAT EXCHANGER	1560			1560			3120
FLUE GAS FANS	4050			4050			8100
							74994

Form No. 9-324A

Design Calculations Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECA	Date: 9/13/90
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: 90206PC-2	Sheet: 116 of

PILOT PLANT OUTLET HEADERS

FLUE GAS

ASSUME 150' OF 42"Ø STD WEIGHT CARBON STEEL PIPE w/ 6" THK INSULATION

FROM GRINNELL, P49

PIPE WEIGHT = 167 lb/FT
INSULATION WEIGHT = 73 lb/FT
TOTAL WEIGHT 240 lb/FT

$\therefore$ OUTLET GAS HEADER = $\frac{150\text{ FT} \mid 240\text{ lb}}{\mid \text{FT}}$ = 36000 lb

FLUE GAS ISOLATION DAMPER

ASSUME 42"Ø A-C BUTTERFLY VALVE MODEL 53FR w/ ACTUATOR

FROM A-C CATALOG VA1.29, P102

VALVE WEIGHT = 3000 lb
ACTUATOR WEIGHT = 300 lb
TOTAL WEIGHT 3300 lb

$\therefore$ $\frac{3300\text{ lb} \mid 1\text{ VALVE}}{\text{VALVE} \mid}$ = 3300 lb

Form No. 9-324A

Design Calculations Southern Company Services

Project DOE SCR PROJECT	Prepared By ECH	Date 9/19/93
Subject/Title ESTIMATED WEIGHTS	Reviewed By	Date
	Calculation Number 90106PE-3	Sheet 17 of

AIR HEADER

ASSUME 150' OF 30"Ø STD WEIGHT CS PIPE WITH 6" THK INSULATION

FROM GRINNELL, P45

PIPE WEIGHT = 119 lb/FT
INSULATION WEIGHT = 55 lb/FT
TOTAL WEIGHT = 174 lb/FT

$\therefore$ AIR HEADER WEIGHT = $\frac{150 \text{ FT} \mid 174 \text{ lb}}{\mid \text{FT}}$ = 26,100 lb

AIR ISOLATION DAMPER

ASSUME 30"Ø ALLIS-CHALMERS BUTTERFLY VALVE MODEL 30PR WITH ACTUATOR

FROM A-C CATALOG VA1.29, P102

VALVE WEIGHT = 1600 lb
ACTUATOR WEIGHT = 300 lb
TOTAL WEIGHT = 1900 lb

$\therefore$ AIR ISOLATION DAMPER WEIGHT = $\frac{1900 \text{ lb} \mid 1 \text{ VALVE}}{\text{VALVE} \mid}$ = 1900 lb

Form No. 9-324A

Design Calculations — Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECH	Date: 9/19/91
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: 90206PE-3	Sheet 18 of

MISCELLANEOUS

INSTRUMENTATION SHACK

ASSUME 2000lb SHACK LOCATED NEAR TOP OF ZR'S FOR FLUE GAS ANALYSIS EQUIPMENT.

2000 lb

AMONIA AIR PIPING

ASSUME 100' OF 1½" STD WT CS PIPE WITH 3" THK INSULATION PER RXR TRAIN.

FROM GRINNELL, p 26

PIPE WEIGHT = 3 lb/FT
INSULATION WEIGHT = 5 lb/FT
TOTAL WEIGHT = 8 lb/FT

$$\therefore NH_3/AIR\ PIPING = \frac{8\ lb}{FT} \left| \, 100\ FT \, \right| \, 9 = 7200\ lb$$

Form No. 9-324A

Design Calculations Southern Company Services

Project: DOE SCR PROJECT	Prepared By: ECM	Date: 9/19/9
Subject/Title: ESTIMATED WEIGHTS	Reviewed By:	Date:
	Calculation Number: 9020SPE-3	Sheet: 19 of

PILOT PLANT SUMMARY

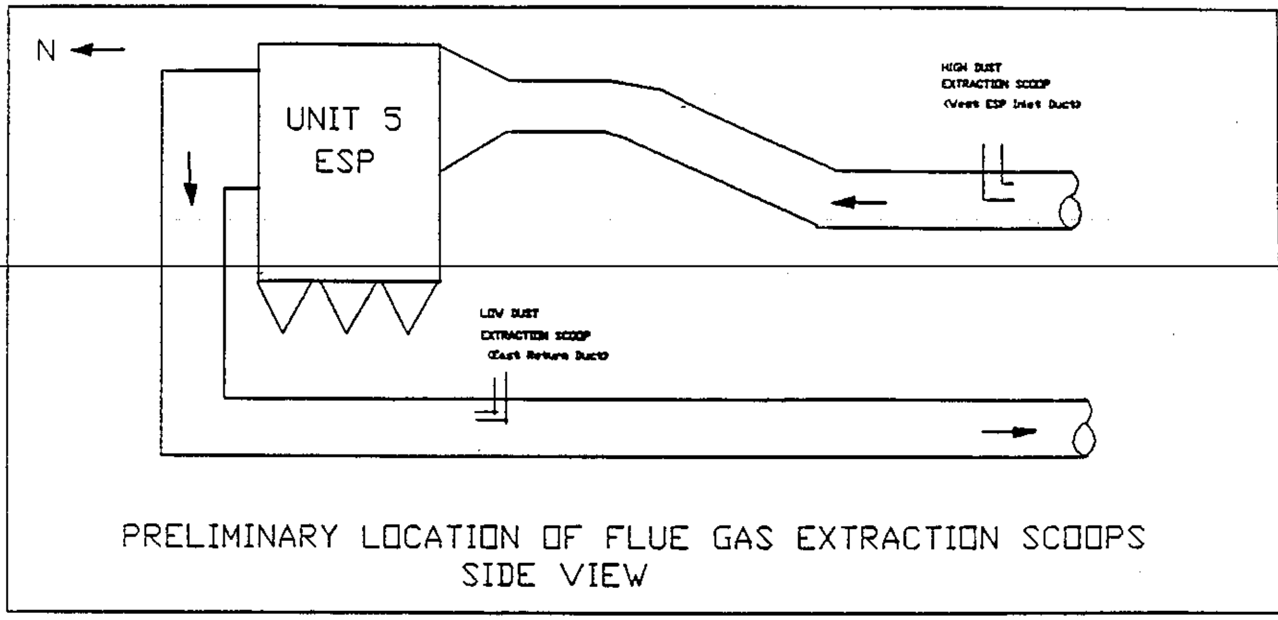
INLET HEADER AREA (p 1)	69,000 lb
LARGE REACTOR TRAINS (p 9)	334,316 lb
SMALL REACTOR TRAINS (p 15)	74,994 lb
OUTLET HEADER AREA (p 16)	67,300 lb
MISCELLANEOUS (p 18)	9200 lb
SUBTOTAL	554 810 lb
MARGIN (15%)	83,222 lb
TOTAL	638,032 lb

– SAY 638,000 lb OR 319 TONS

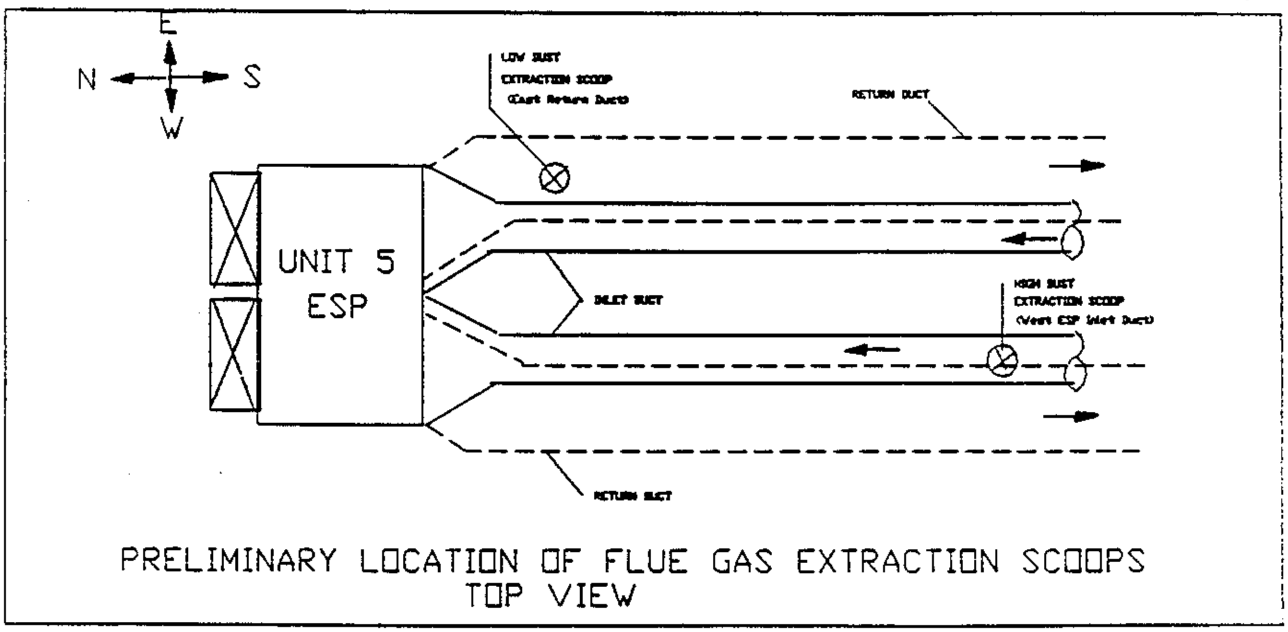
Form No. 9-324A

3.0 AREA 100: FLUE GAS EXTRACTION SCOOP TO FLUE GAS DISTRIBUTION HEADER

Area 100 includes the area from the flue gas extraction scoop to the flue gas distribution header. A sketch of the location of the flue gas extraction scoops for the high dust and low dust extraction locations for Unit 5 is shown in Figure 3.0-1. The high dust extraction scoop is located in the west side hot-ESP inlet duct near the duct sampling ports. The high dust extraction scoop will remove flue gas from the main duct to supply flue gas to the three large reactors and five of the small reactors, for a nominal capacity of 17,000 scfm. The low dust extraction scoop will be located in the east side hot-ESP outlet duct. The low dust extraction scoop will supply nominally 400 scfm to one of the small reactors, and will utilize one of the existing sampling ports on the east side hot-ESP exit duct. A listing of the major equipment for this area is found in Section 3.2.2.



a. Side view.



b. Top view.

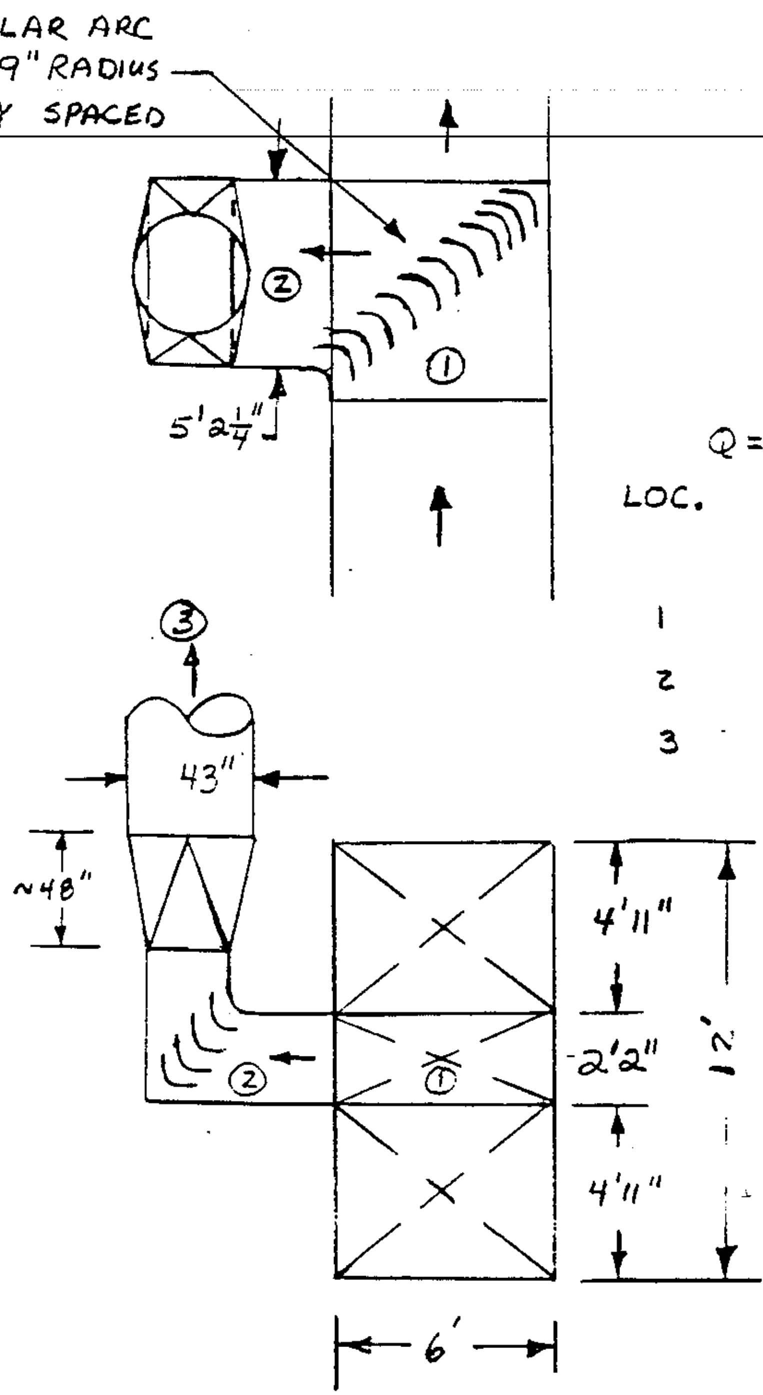
Figure 3.0-1. Preliminary location of flue gas extraction scoops.

3.1 AREA 100 DESCRIPTION

Results from Southern Research Institute (SRI) ductwork testing indicated that the boiler ducts are well vaned on Unit 5, both at the ESP inlet and outlet. Particulate mass loading, ductwork gas velocity, flue gas temperature, and NOx distributions appear to be fairly uniform across the duct cross section at high and low loads as shown in EXHIBIT 3.1-A. The flue gas extraction scoop will have a rectangular geometry and be located in the center of the boiler duct. The center of the duct was chosen for several reasons: (1) This will give the most representative sample at all loads since the sample will be drawn equally from the top and bottom of the duct, thereby minimizing sample bias; (2) the flue gas flow around the scoop, when not in use, gives a better stream line effect, causing the flow disturbance to dampen out quicker; (3) installation and support of the scoop will be easier; (4) the scoop inlet can be adequately characterized using the existing sample ports. The height dimension of the scoop will be a function of the final face velocity needed to approach isokinetic operation. (See Exhibit 3.1-B.)

The measured velocity in the boiler duct ranged between 30 to 35 fps at low load, to 45 to 50 fps at high load. Based on a scoop face velocity of about 46.6 fps, the scoop design would be 6 ft wide x 2 ft-2 in high and would block approximately 18 percent of the boiler duct area when not in use. The extraction scoop will be designed with turning vanes, accelerating flue gas from the extracted velocity to the design pilot plant ductwork velocity of 60 fps. The scoop geometry is depicted in Figure 3.1-1. Additional recommendations for the scoop include: (1) all edges of the scoop should be sharpened; (2) no horizontal stiffeners plate in between guide vanes; and (3) guide vanes will be designed as in the Handbook of Hydraulic Resistance (Idelchik).

Extraction scoops for the small reactors will be taken off the large reactor feed duct, which only requires 1 extraction scoop in the host boiler duct. Dynagen has modeled the boiler duct and extraction scoop to determine the host



Q = 36,356 ACFM

LOC.	AREA FT²	VELOCITY FPS
1	13.0	46.6
2	11.24	53.9
3	10.10	60.0

Figure 3.1-1. Extraction scoop concept, SCR project (front, top and side views).

unit draft loss and to observe the flow patterns of the gas extraction. There will be no overall pilot plant model.

Flow modeling of the main flue gas duct and the effect on the scoop in the main duct has been done on a 1/9 scale model, with the extent of the model and location of scoop and traverses as depicted in Figure 3.1-2. Figures 3.1-3 and 3.1-4, iso-velocity contours of Unit 5 duct model, show that the model represents the actual plant duct very well, usually +/- 2 to 3 percent variation. The increased pressure drop from adding the scoop is only about a one-half duct velocity head, or 0.11 in. of water gauge pressure loss, as shown in Figure 3.1-5.

As indicated in Figures 3.1-6 and 3.1-7, the distance between the scoop and hot ESP inlet is sufficient to allow almost equivalent velocity profiles at the ESP inlet with or without the scoop. Thus, changes in flow introduced by the scoop are dampened out by the time the flue gas enters the downstream ESP, and the scoop is not expected to have any deleterious effects on the main flue gas flow patterns.

Data presented in Table 3.1-1 indicates there should not be a problem in dust stratification in pilot plant ducts. However, by taking gas from the main duct with the scoop and reducing the main gas velocity, the potential for fallout in the main duct between the scoop and ESP inlet is increased, primarily at low boiler loads. Whether this is a problem that Crist is experiencing now will be verified with Gulf Power Company, and after pilot plant operation begins, inspection of this portion of the main flue gas duct may be done during Unit 5 downtime periods, and if needed, any ash build-up could be removed.

Other potential consequences of introducing the scoop into the main flue gas duct include the following:

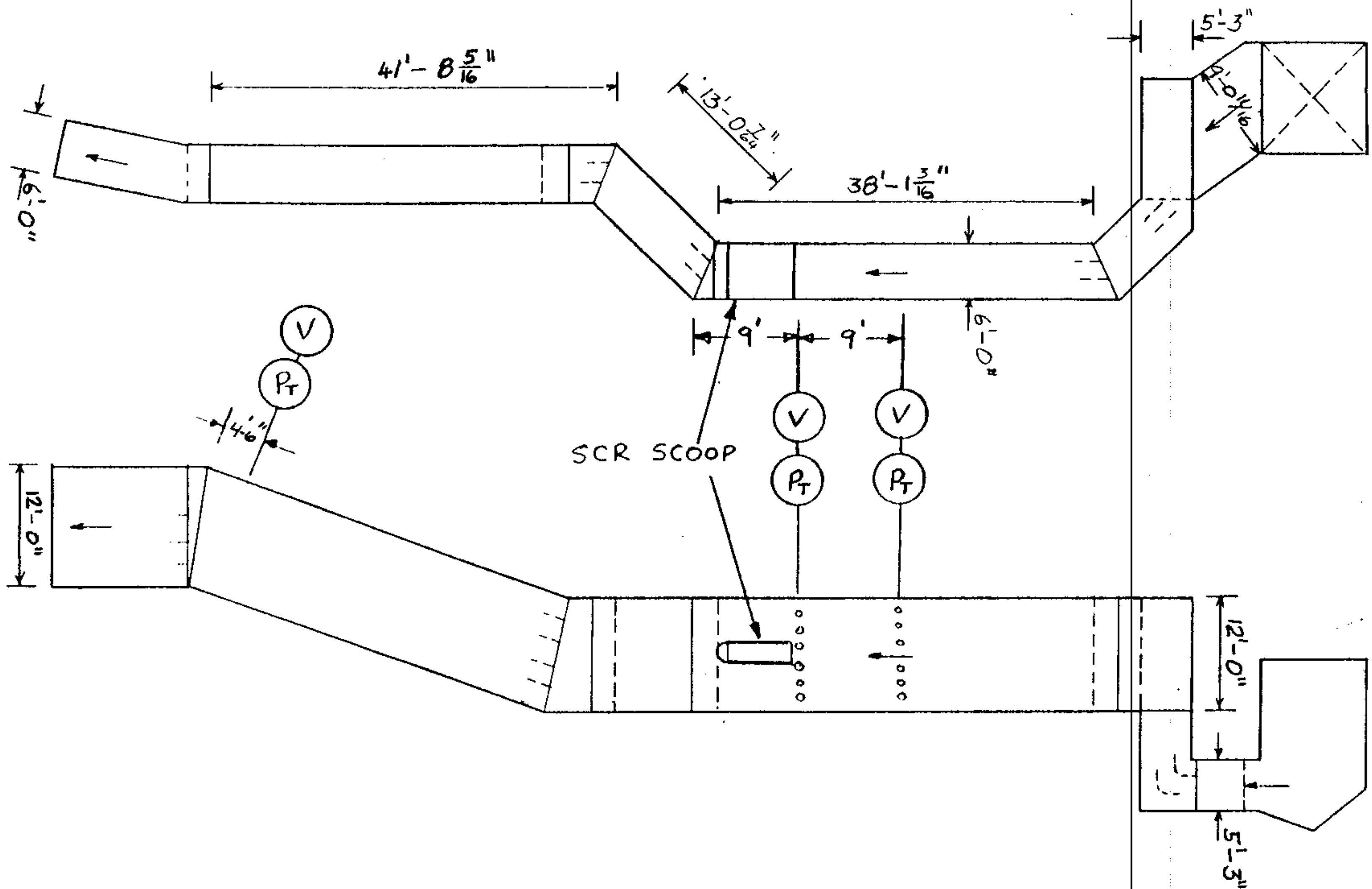


Figure 3.1-2. Location of scoop and traverse.

Traverse Location UPSTREAM OF SCOOP
Flow Condition FIELD HIGH FLOW CONDITION
Simulated Duct Flow 197,860 ACFM
Simulated Scoop Flow NO SCOOP IN PLACE

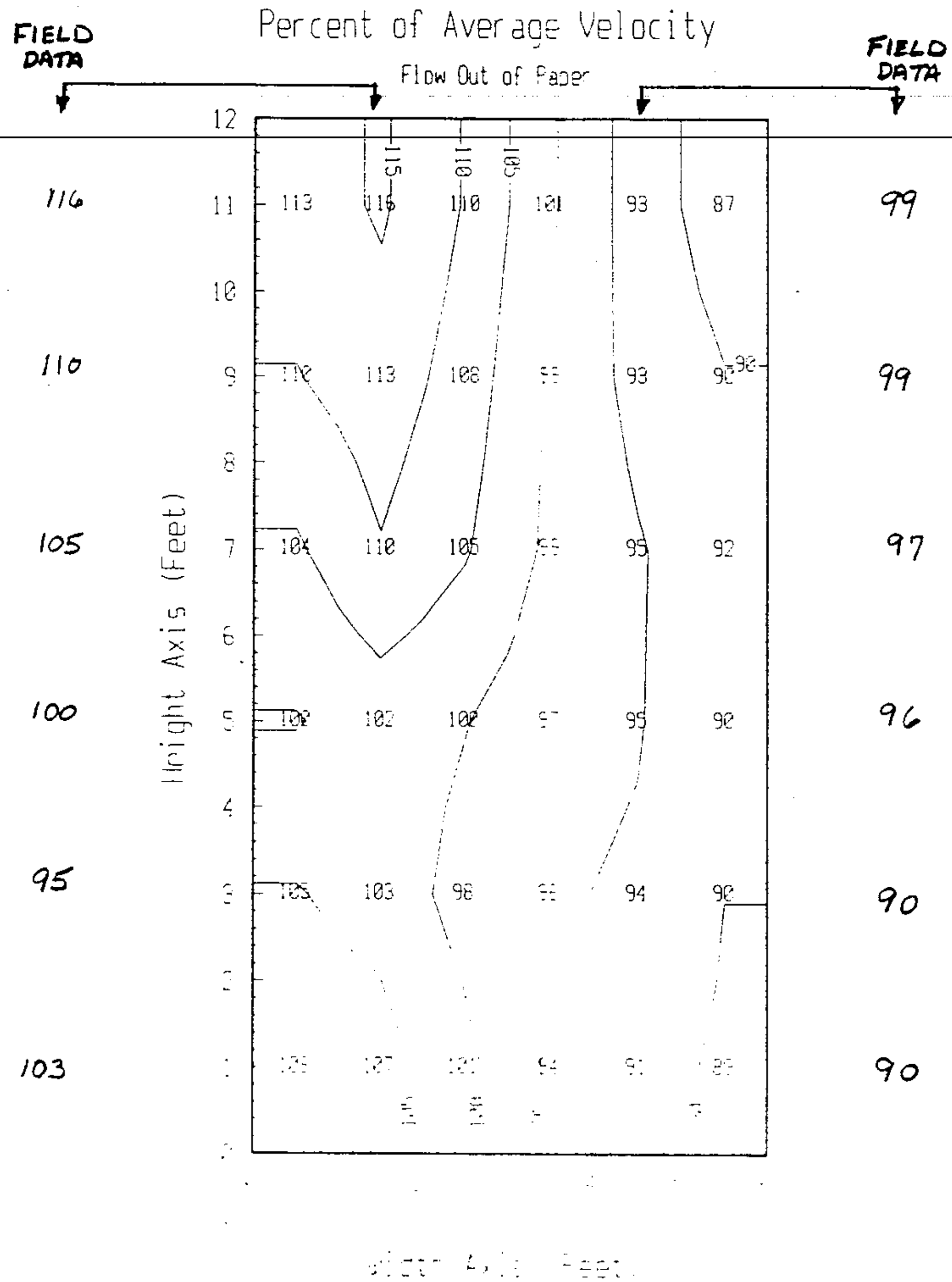


Figure 3.1-3. Iso-velocity contours of Unit 5 duct model — upstream of scoop.

Traverse Location NEAR ESP INLET
Flow Condition FIELD HIGH FLOW CONDITION
Simulated Duct Flow 197,860 ACFM
Simulated Scoop Flow NO SCOOP IN PLACE

Percent of Average Velocity

Flow Out of Paper

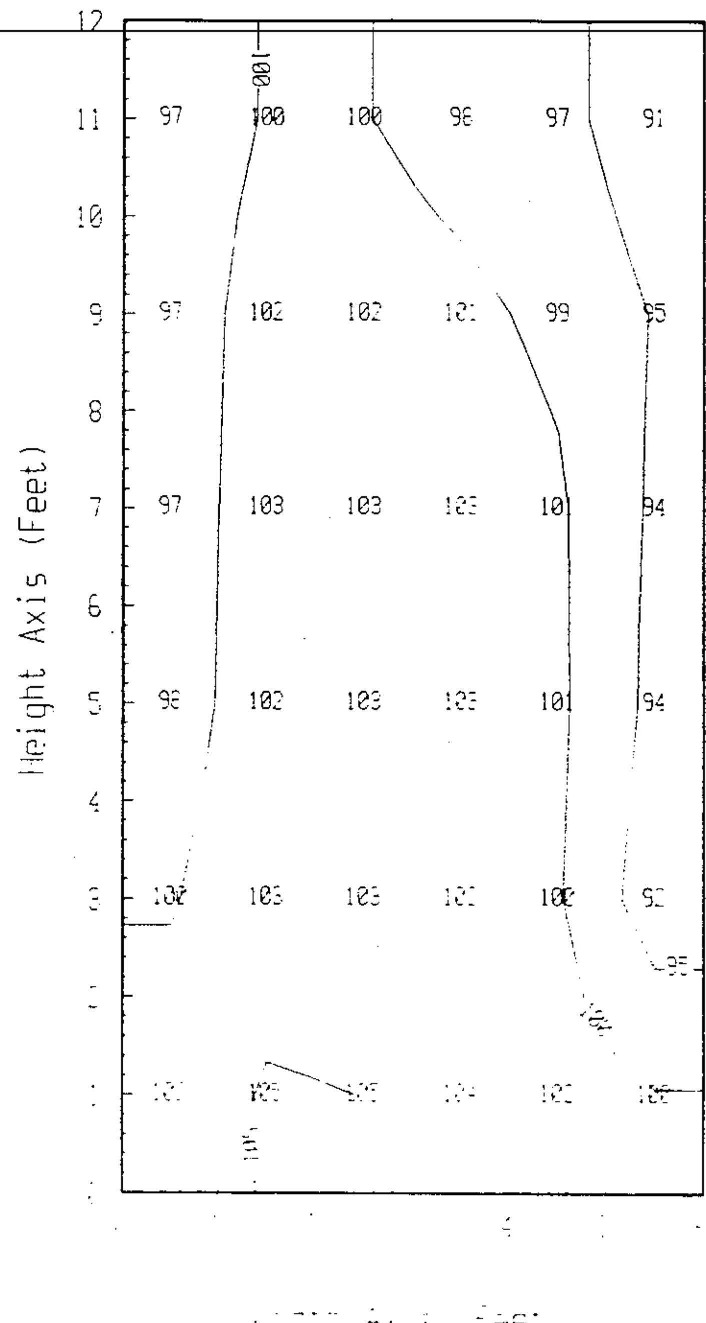


Figure 3.1-4. Iso-velocity contours of Unit 5 duct model — near ESP inlet/with no scoop.

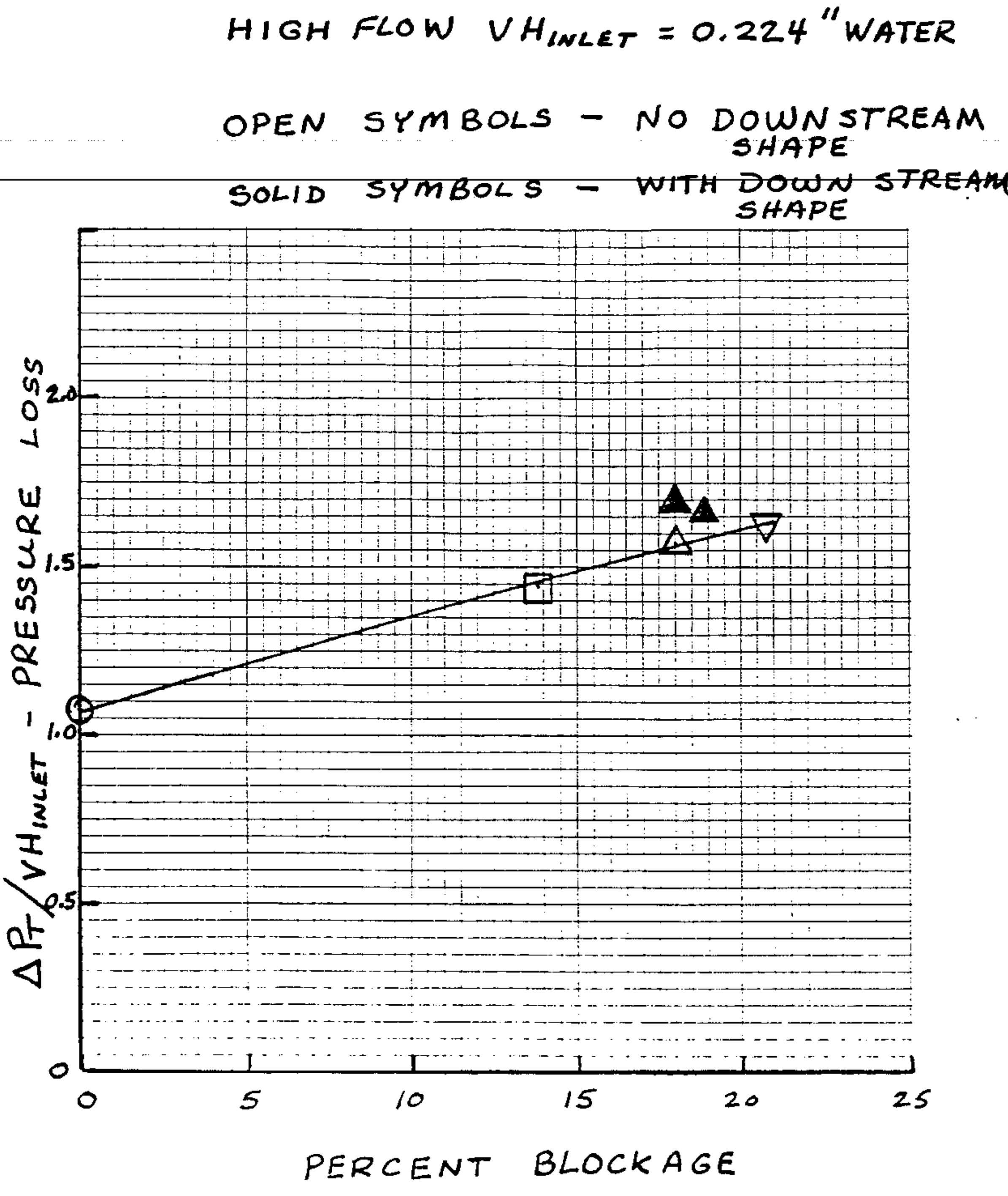


Figure 3.1-5. Pressure loss in Unit 5 duct model.

Traverse Location NEAR ESP INLET
Flow Condition FIELD HIGH FLOW CONDITION
Simulated Duct Flow 197,860 ACFM
Simulated Scoop Flow SCOOP IN PLACE / ZERO FLOW

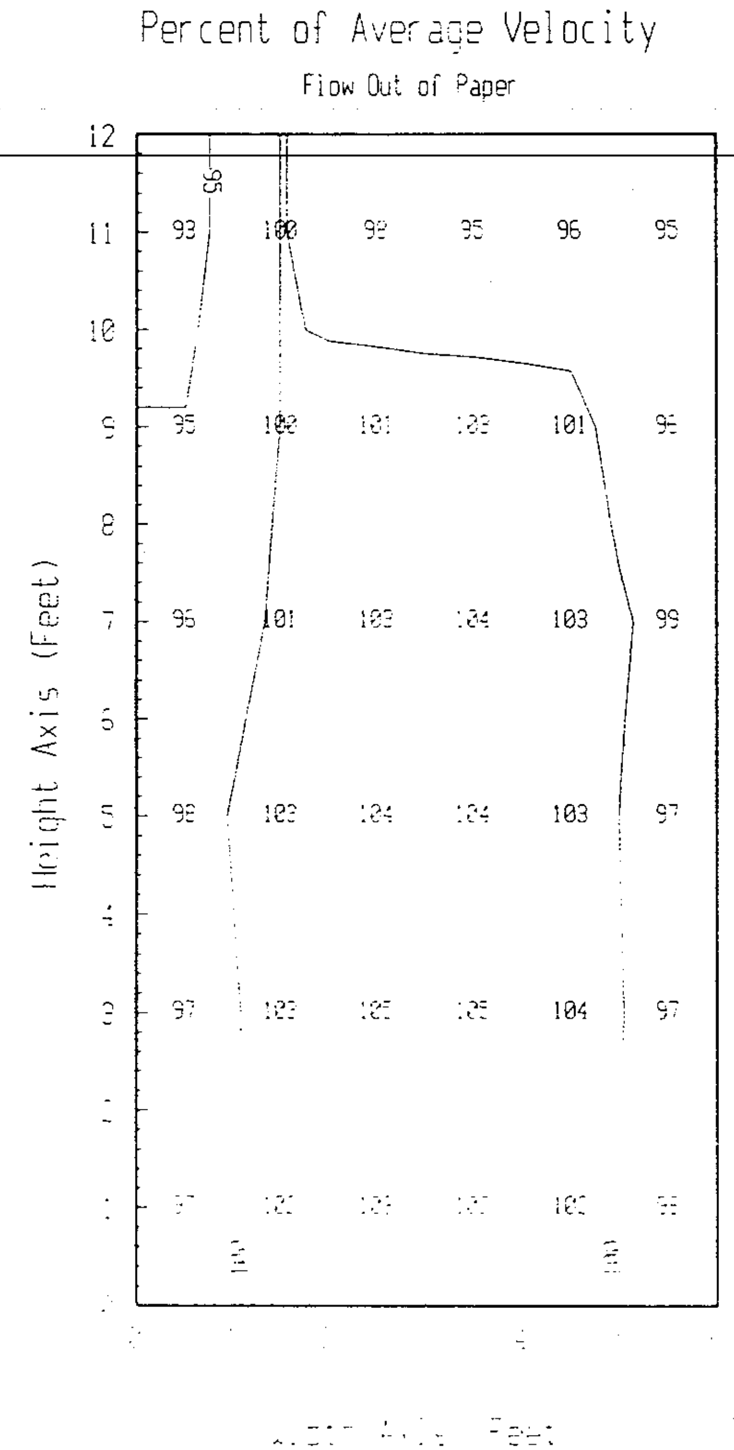


Figure 3.1-6. Iso-velocity contours of Unit 5 duct model — near ESP inlet/with scoop in place.

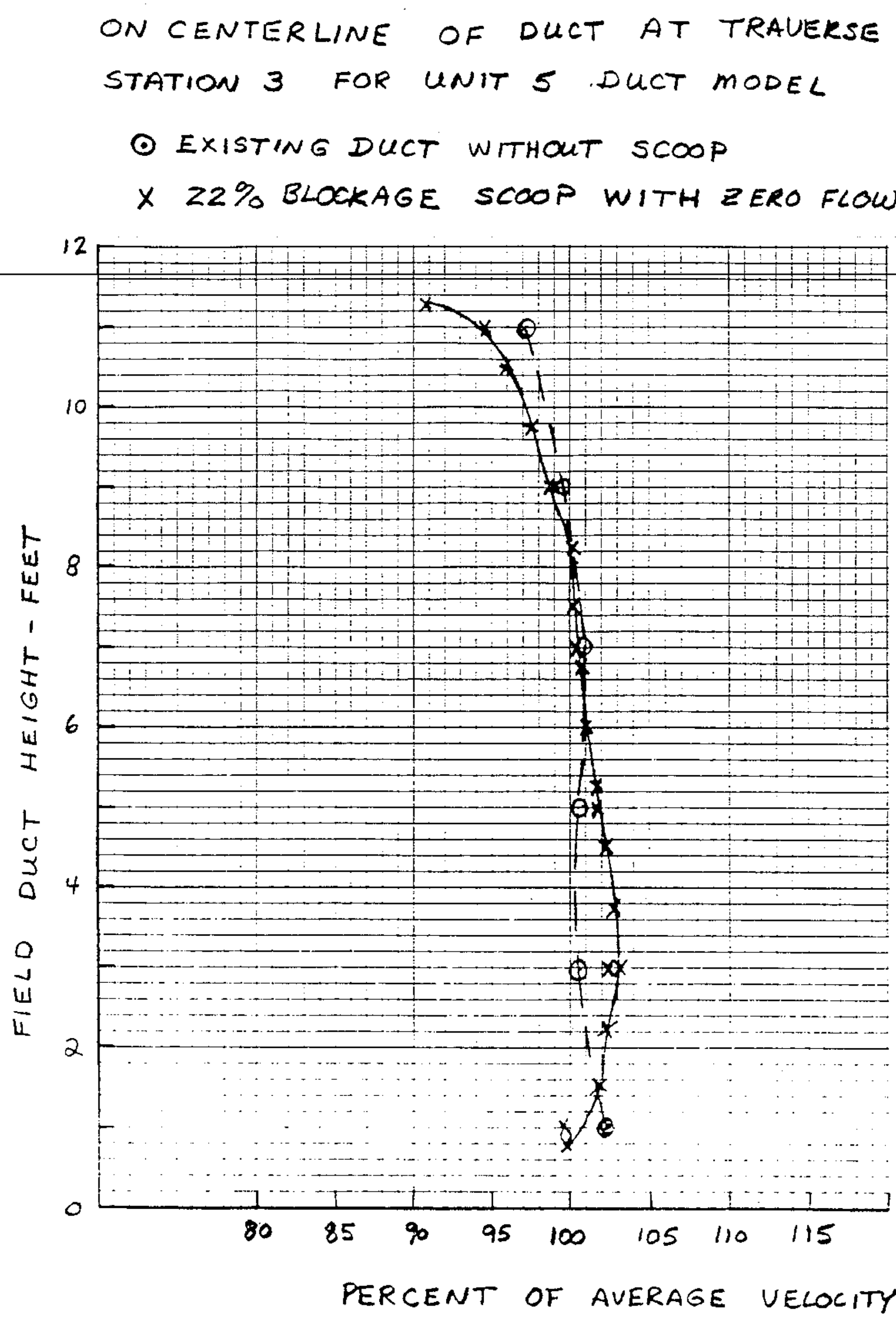


Figure 3.1-7. Velocity profile with/without scoop.

Table 3.1-1

Flyash Settling in Pilot Plant Ducts at 60fps

Weight %	Less than μ (microns)	Terminal Velocity fps	Downward Movement In 1 second or 60 feet
95	90	1.10	13.2"
90	57	0.44	5.3"
80	38	0.196	2.35"
60	21	0.060	0.72"
50	16	0.035	0.42"
40	13	0.023	0.28"
20	6.6	0.0059	0.071"
10	3.4	0.0016	0.019"
1	1.1	0.00016	0.0019"

- Dust accumulation in the scoop at no flow — During periods when the pilot plant is not operating but Unit 5 remains on-line, ash build-up may occur in the scoop. In considering alternative solutions to prevent significant ash loading from damaging the catalyst in the reactor upon pilot plant startup, design changes were made, and the reactor bypass will be used upon each startup.

- Vibration of downstream vanes in main duct — There will be a slight increase in forces acting on the vanes; stiffeners will be added for additional support, if needed.

- Scoop location — If it became necessary to reduce pressure loss of unsteady forces on the vanes, the scoop would be moved upstream 9 to 12 ft, which would produce equivalent velocity profiles.

As noted above, the difference between high and low load main flue gas duct velocities may be about 15 fps. The extraction velocity during low load may be about 50 percent higher than the duct velocity. The ash concentration is less during low load, and thus there should be no significant increase in ash to the test facility. However, the effect has to be considered when determining NH_3 slip by using the method of analyzing for NH_3 on fly-ash. Thus, during commissioning ash measurement by extraction is recommended at various loads for NH_3 mass balance calculations.

The extraction of the flue gas for eight of the SCR reactor trains from the west ESP inlet duct was estimated to potentially exacerbate an existing problem with the Unit 5 APH cold end temperatures. (See the text under Area 500, SCR reactor outlet to pilot APH outlet, for discussion of the problems and resolution for flue gas/air disposition.)

The material of construction for the piping ductwork and reactors on the pilot-scale SCR facility will be low carbon steels. Either ASTM A53 or ASTM A106 will be used for the piping ductwork, while the steel plate for the reactors will be constructed of ASTM A516 or ASTM A204.

The insulation will be a non-asbestos material. A calcium silicate material will be used for piping ductwork while mineral wool may be used with the reactors. Both materials are typical of normal power plant insulators. Theoretical calculations indicate a drop in the flue gas temperature of only 2°F from the extraction scoop to the reactors.

However, because of non-ideal conditions, losses throuth test ports, flanges, expansion joints, and dampers, etc., the actual expected temperature loss is about five times the theoretically-calculated loss. As a result, a thickness of about one ft of insulation will be used for the ductwork to the reactor inlet. In addition, the ductwork will be heat traced to further reduce heat loss. Vendor information on typical ductwork heat tracing is shown in Exhibit 3.1-C.

3.1.1 Economizer Bypass

As discussed in Section 2.3.3, the vapor phase trace metal composition in the flue gas may decrease as a result of (1) temperature drop between the boiler-economizer outlet and extraction scoop and between the scoop and heater or pilot SCR reactor; (2) flue gas residence time in the duct; and (3) heater surface temperature. A change in this vapor phase metal composition resulting from temperature drops may lead to different, possibly improved, catalyst deactivation rates than would normally be achieved on a full-scale facility. As a result, maintaining temperatures and minimizing heat loss, in addition to the thicker insulation and heat tracing on the inlet ductwork to the reactor mentioned in the preceeding paragraphs, the project scope has been increased to include an economizer bypass. A sketch of the economizer bypass is shown in Figure 3.1-8.

SCS/DOE SELECTIVE CATALYTIC REDUCTION PROJECT
ECONOMIZER BYPASS CONCEPT

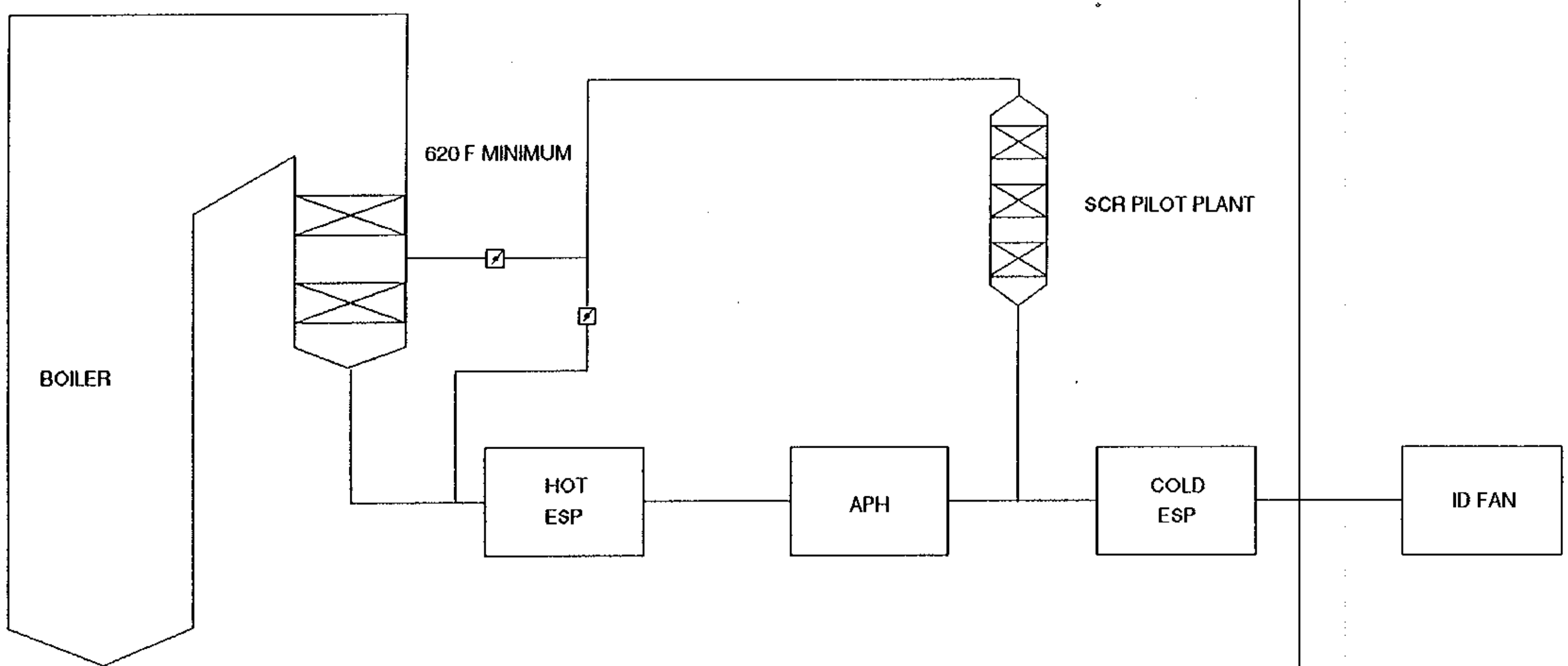


Figure 3.1-8. Scketch of economizer bypass

The temperature of the pilot plant flue gas being extracted and sent to the distribution header for the SCR reactors will be monitored. This measurement will be used to control a flow control damper on the economizer bypass line to maintain a minimum temperature of 620°F for the flue gas entering the pilot plant system. As the boiler load decreases from full load and the temperature of the extracted flue gas decreases below 620°F, the damper will open, allowing hotter flue gas from above the boiler-economizer region to mix with and raise the temperature of the flue gas entering the SCR system. Trace metal vapor phase condensation is minimized, and the catalyst is exposed to a more similar level of potential poisons as would be expected in a commercial system.

Sizing of the economizer bypass line will be completed upon finalizing tie-in locations and temperature profiles for Unit 5. Preliminary results from a computer model used to size the economizer bypass line are shown in Figure 3.1-9 and Table 3.1-2.

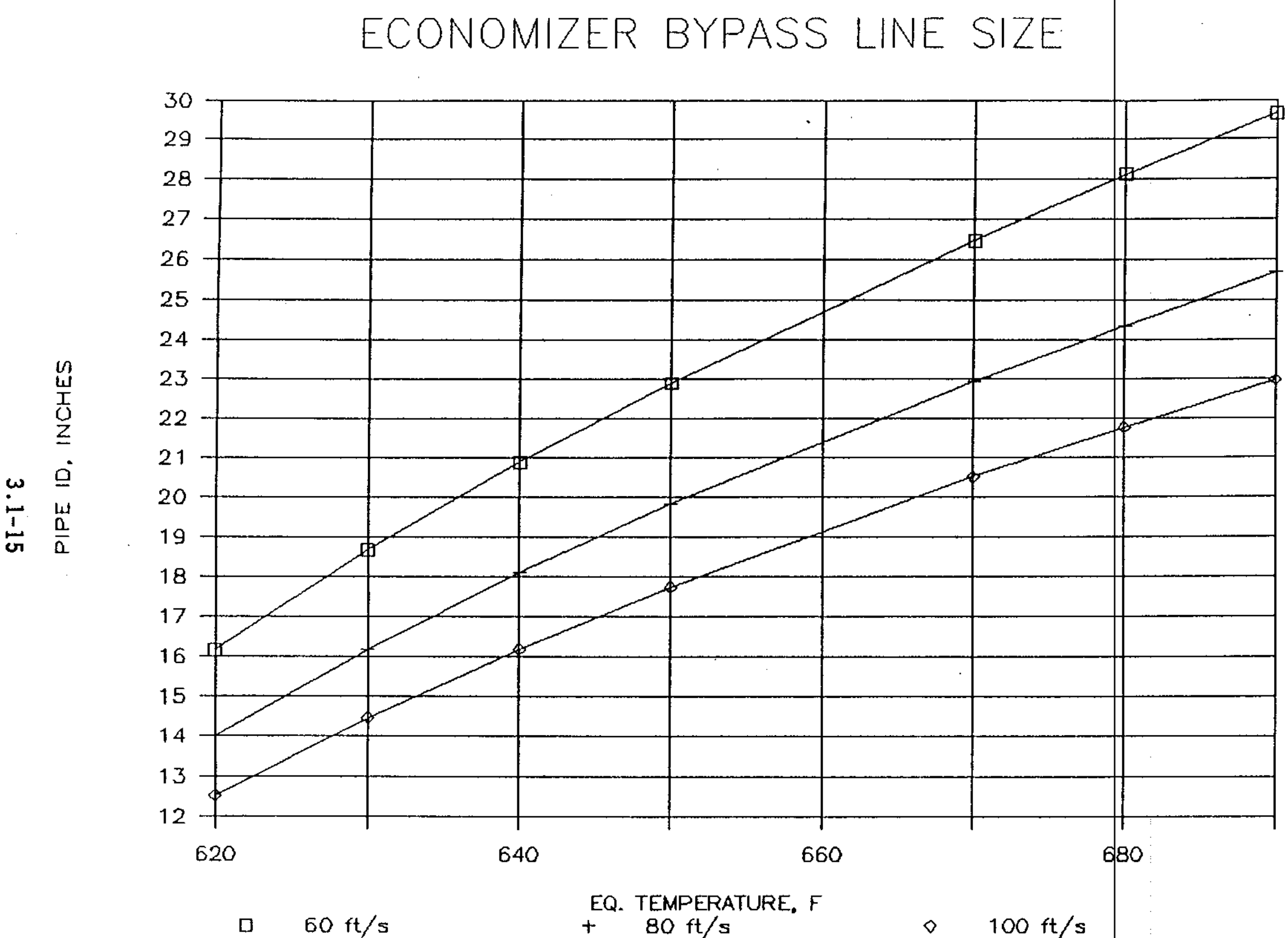


Figure 3.1-9. Preliminary results from a computer model used to size the economizer bypass line.

Table 3.1-2

Economizer Bypass Line Size

11/29/90

SCR PROJECT – ECONOMIZER BYPASS LINE SIZE

	MW	WT% of FLUE GAS	Cp at 850 F	Cp at 590 F
N2	28.02	70.1%	0.265	0.260
O2	32.00	3.2%	0.250	0.240
CO2	44.01	20.8%	0.288	0.260
H2O(v)	18.02	5.9%	0.500	0.480
		100.0%		
Ave. Cp, Btu/lb F			0.28	0.27

Teq (F)	Tx (F)	Ty (F)	My/Mx	Mx, lb/hr	SCFM	ACFM
690	850	590	1.66	31623	6381	17273
680	850	590	1.96	28418	5735	15523
670	850	590	2.34	25223	5090	13778
650	850	590	3.47	18861	3806	10302
640	850	590	4.37	15694	3167	8573
630	850	590	5.72	12537	2530	6848
620	850	590	7.97	9389	1895	5128

Teq (F)	X-SECT. AREA at 60 ft/s	Pipe ID inches	X-SECT. AREA at 80 ft/s	Pipe ID inches	X-SECT. AREA at 100 ft/s	Pipe ID inches
690	4.80	29.7	3.60	25.7	2.88	23.0
680	4.31	28.1	3.23	24.4	2.59	21.8
670	3.83	26.5	2.87	22.9	2.30	20.5
650	2.86	22.9	2.15	19.8	1.72	17.7
640	2.38	20.9	1.79	18.1	1.43	16.2
630	1.90	18.7	1.43	16.2	1.14	14.5
620	1.42	16.2	1.07	14.0	0.85	12.5

EXHIBIT 3.1-A

SRI DUCT SAMPLING RESULTS FOR PLANT CRIST UNIT 5

PRELIMINARY

9/17/90

► E

Particulate Mass Loading, gr/acf

Sampling Ports	Range: / Average:	
1	1.23–1.45 1.33	1.27–1.38 1.33
2	1.33–1.50 1.39	1.38–1.41 1.40
3	1.32–1.47 1.40	1.50–1.76 1.61
4	1.59–1.61 1.60	1.67–1.76 1.69
5	1.96–2.15 2.06	1.62–1.97 1.80
6	1.65–1.71 1.68	1.61–1.74 1.68

Gas Velocity, ft/sec

Sampling Ports	Range: / Average:	
1	44.8–46.0 45.40	52.4–54.2 53.13
2	44.7–45.4 45.17	49.8–51.8 50.50
3	43.3–44.7 44.30	47.9–48.5 48.13
4	43.8–44.5 44.15	45.2–45.9 45.55
5	40.9–41.7 41.30	43.1–43.8 43.45
6	40.1–41.6 40.85	46.4–48.4 47.40

Temperature, F

Sampling Ports	Range: / Average:	
1	655–661 658	655–663 658
2	654–660 657	656–661 658
3	652–659 655	650–660 654
4	640–650 645	646–649 648
5	642–643 643	642–644 643
6	638–638 638	641–643 642

UNIT 5 - ESP INLET DUCT - HIGH LOAD (85 MW)

(Gas flow into the plane of the page)

PRELIMINARY

9/17/90

E

NO Concentration, ppm (dry, not corrected for constant O2)

Sampling Ports	Range / Average	Range / Average	Range / Average
1	289–322 313	275–323 309	294–352 332
2	277–321 309	259–321 305	317–337 327
3	302–325 318	298–326 317	314–335 326
4	298–327 317	290–333 318	314–348 334
5	276–331 313	308–329 318	321–335 317
6	289–330 315	284–330 314	296–341 325

NOx Concentration, ppm (dry, not corrected for constant O2)

Sampling Ports	Range / Average	Range / Average	Range / Average
1	292–345 326	275–344 322	298–355 334
2	277–345 322	285–346 326	317–352 337
3	306–354 336	298–352 333	318–354 342
4	298–358 334	301–358 338	321–360 346
5	279–360 332	309–361 338	286–362 335
6	298–358 330	284–359 331	299–367 338

O2 Concentration, %

Sampling Ports			
1	2.9	3.0	3.0
2	2.5	2.1	2.9
3	2.8	2.8	3.0
4	3.0	3.2	3.4
5	3.4	3.0	3.0
6	3.2	3.3	2.8

UNIT 5 - ESP INLET DUCT - HIGH LOAD (85 MW)

(Gas flow into plane of the page)

PRELIMINARY

9/17/90

E

Particulate Mass Loading, gr/acf

Sampling Ports	Range: / Average:	
1	1.27–1.62 1.45	1.22–1.26 1.24
2	1.25–1.51 1.38	1.19–1.43 1.31
3	1.35–1.37 1.36	1.36–1.51 1.44
4	1.36–1.55 1.46	1.44–1.53 1.49
5	1.49–1.78 1.64	1.40–1.43 1.42
6	1.52–1.88 1.70	1.51–1.52 1.52

Gas Velocity, ft/sec

Sampling Ports	Range: / Average:	
1	29.4–32.3 30.8	35.6–37.3 36.5
2	29.4–32.3 30.8	33.0–34.4 34.4
3	29.4–30.4 29.9	31.2–36.3 33.8
4	28.3–31.3 29.8	29.3–32.2 30.8
5	28.3–29.2 28.8	29.2–31.2 30.2
6	28.1–29.2 28.7	32.0–33.8 32.9

Temperature, F

Sampling Ports	Range: / Average:	
1	595–598 597	595–598 597
2	594–600 597	591–599 595
3	594–599 597	593–598 596
4	590–594 592	589–594 592
5	584–585 585	584–587 587
6	577–584 581	580–587 584

UNIT 5 - ESP INLET DUCT - LOW LOAD (45 MW)
(Gas flow into plane of the page)

PRELIMINARY

9/17/90

► E

NO Concentration, ppm (dry, not corrected for constant O2)

Sampling Ports	Range: / Average:		
1	245–390 / 312	227–390 / 306	224–380 / 305
2	267–380 / 319	249–390 / 316	229–380 / 306
3	271–380 / 324	264–390 / 321	260–380 / 317
4	289–380 / 330	282–380 / 327	261–380 / 324
5	283–380 / 331	281–380 / 324	275–380 / 325
6	287–380 / 332	280–380 / 330	283–390 / 334

NOx Concentration, ppm (dry, not corrected for constant O2)

Sampling Ports	Range: / Average:		
1	248–400 / 323	227–390 / 309	224–380 / 305
2	270–400 / 330	251–400 / 324	235–390 / 315
3	279–390 / 336	269–400 / 333	261–400 / 330
4	298–380 / 343	288–400 / 343	266–390 / 332
5	295–400 / 352	288–390 / 343	284–400 / 345
6	298–400 / 353	298–400 / 353	313–400 / 358

O2 Concentration, %

Sampling Ports			
1	7.6	7.9	7.2
2	7.9	7.3	7.1
3	7.6	7.7	7.5
4	7.4	7.8	7.8
5	7.4	7.7	7.6
6	7.3	7.2	7.1

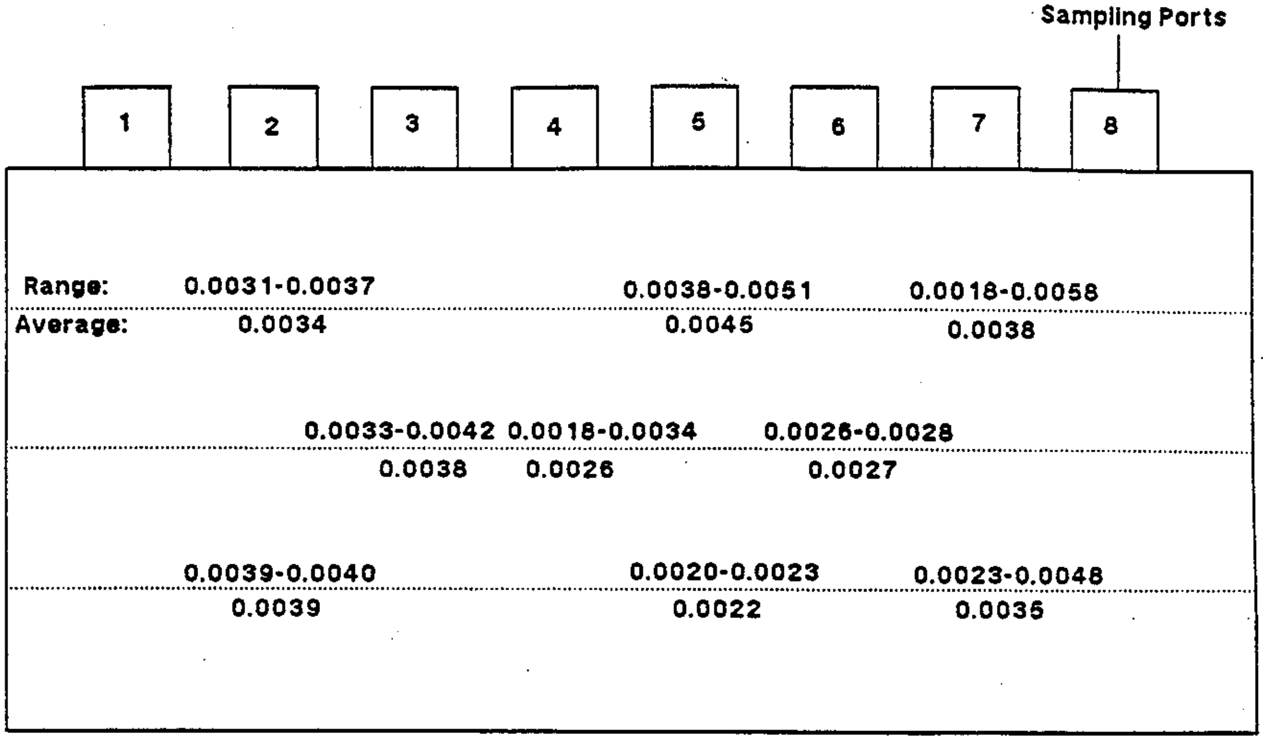
UNIT 5 – ESP INLET DUCT – LOW LOAD (45 MW)

(Gas flow into plane of the page)

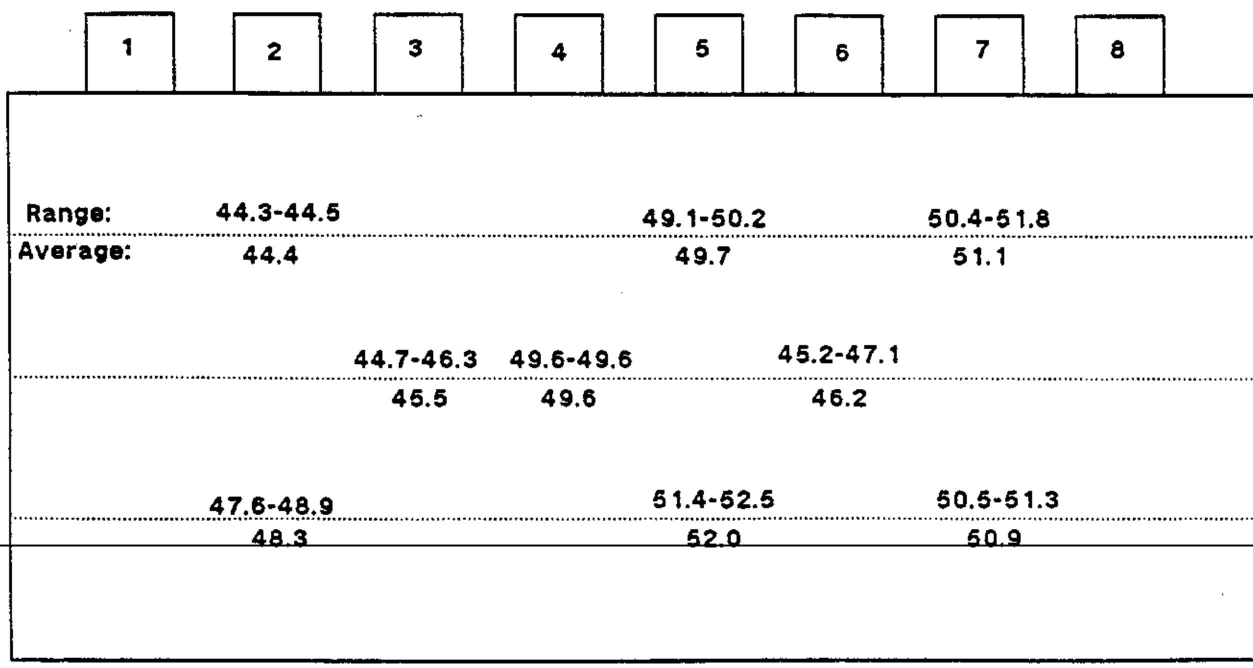
PRELIMINARY

E ◄

9/17/90



Particulate Mass Loading, gr/acf



Gas Velocity, ft/sec

UNIT 5 - ESP OUTLET DUCT - HIGH LOAD (85 MW)

(Gas flow into plane of the page)

E ◄ PRELIMINARY 9/17/90

Sampling Ports

	1	2	3	4	5	6	7	8
Range:		661-616			616-620		603-611	
Average:		614			618		607	
			607-619	616-617		610-613		
			613	617		612		
		613-614			616-617		606-615	
		614			617		611	

Temperature, F

	1	2	3	4	5	6	7	8
Range:		4.0-5.0	4.2-4.8	4.2-4.9	4.2-4.9	4.2-5.0	4.1-5.2	
Average:		4.5	4.5	4.6	4.6	4.6	4.7	
		4.0-5.0	4.1-4.8	4.1-5.0	4.4-5.1	4.4-5.1	4.2-4.6	
		4.5	4.5	4.6	4.8	4.8	4.4	
		3.5-4.8	4.3-4.9	4.8-5.1	5.1-5.8	4.7-5.8	4.8-5.0	
		4.2	4.6	5.0	5.5	5.3	4.9	

O2 Concentration, %

UNIT 5 - ESP OUTLET DUCT - HIGH LOAD (85 MW)

(Gas flow into plane of the page)

PRELIMINARY

E ◄ 9/17/90

Sampling Ports

	1	2	3	4	5	6	7	8
Range:		315-347	301-367	282-352	303-345	310-334	315-329	
Average:		331	334	317	324	322	322	
		313-357	295-382	309-353	301-351	301-337	312-334	
		335	339	331	326	319	323	
		310-359	298-382	324-362	306-356	313-337	327-337	
		335	340	343	331	325	332	

NO Concentration, ppm
(dry, not corrected for constant O2)

	1	2	3	4	5	6	7	8
Range:		316-347	305-372	284-354	305-347	311-335	320-329	
Average:		332	339	319	326	323	325	
		315-356	296-383	315-358	306-352	305-338	312-335	
		336	340	337	329	322	324	
		331-366	300-383	326-364	313-357	317-341	327-340	
		349	342	345	335	329	334	

NOx Concentration, ppm
(dry, not corrected for constant O2)

UNIT 5 - ESP OUTLET DUCT - HIGH LOAD (85 MW)

(Gas flow into plane of the page)

EXHIBIT 3.1-B

DYNAGEN'S DISCUSSION OF FLUE GAS EXTRACTION, DATED 9/18/90

DISCUSSION OF BASIC DESIGN FOR THE SCR PILOT PLANT SYSTEM BEING DESIGNED FOR THE CRIST STEAM PLANT

DynaGen, Inc. Project No. SCS-2
DynaGen, Inc. Report No. 2486
SCS Contract No. 195-89-044
DOE Clean Coal Program

Submitted to:

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, Alabama 35202

Prepared by:

Gerald B. Gilbert

September 18, 1990

Submitted by:

DynaGen, Inc.
99 Erie Street
Cambridge, Massachusetts 02139

Telephone (617) 491-2527

Section 2

DISCUSSION OF FLUE GAS EXTRACTION

2.1 Unit 5 Hot Side Extraction

This extraction location is to provide pilot plant flow to the three large reactors and five out of six small reactors. The amount of design flow to be extracted is as follows:

	Standard SCFM	Approximate Actual ACFM
Three Large Reactors at 5,000 SCFM Each	15,000	31,440
Five Small Reactors at 400 SCFM Each	2,000	4,192
Total	17,000	35,632

Southern Research Institute measured velocity profiles, dust loading distributions, temperature profiles, and concentration profiles of NO, NO_x, and O_2 at an existing duct traverse station that is located in a convenient place for extraction of hot flue gas. The total flow rate in this duct for the high load condition was about 197,770 ACFM and the low load flow rate was about 135,860 ACFM. The extracted flow there represents 18% of the high load condition and 26% of the low load condition. The traverse data at this location shows good uniformity in all parameters for both load conditions. The center region of the duct for all parameters is the most uniform and closest to the average value in the cross-section.

The best location to extract the pilot plant flow is near the traverse location in the center of the duct using a rectangular shaped scoop the full width of the 6' duct dimension. (The duct is 6' by 12' high.) The flow should be withdrawn to the side by a vaned 90° elbow. This should be the best arrangement for the following reasons:

1. The SRI field traverse data shows the region in the center of the duct is the most uniform and nearest the average for all measured quantities.

2. An obstruction in the center of the duct will cause less of a disturbance on the main duct flow that proceeds on to the ESP. With a careful design of the scoop verified by model tests, the affect on pressure loss and main duct

flow distortion can be limited to small amounts. An enlarged scoop blockage area or an offset scoop would probably cause additional pressure loss and flow distortion.

3. A rectangular scoop of about 21% of the duct area would be about 2'-6" by 6'.

A second possible location for extraction would be off the top 2'-6" of the duct with a rectangular vaned scoop which turns upward. This might be a more convenient duct orientation but it would be extracting flow where dust loading is the lowest and concentrations of NO and NO_x are the lowest.

2.2 Unit 5 Cold Side Extraction

Four-hundred (400) SCFM for one small reactor is to be extracted from the cold side of the Unit 5 ESP or Unit 4 ESP.

The Southern Research Institute measured traverse results at the outlet of the hot ESP also showed good uniformity results for all parameters except dust loading which had a low level but a two to one variation. The highest dust loading actually appeared near the top of the duct, however, if you trace the ducts back to the precipitator outlet you will see that this flow came from the bottom of the ESP chamber and would, therefore, be expected to have a higher loading. Since only about 400 SCFM or about 800 ACFM needs to be extracted, the scoop (round or rectangular) could be positioned anywhere in the cross-section to achieve the desired levels of dust loading, NO, and NO_x.

What should be of more concern is the affect of extraction of a large amount of flue gas from the west inlet duct and how this might affect the outlet duct flow extraction. The parameter that would primarily be affected is the dust loading at the outlet duct extraction point due to improved collection effectiveness of the hot ESP at reduced flow. The outlet duct most affected would be the west outlet duct of Unit 5 but the east outlet duct could also be affected if there is no partition plate in the center of the hot ESP. To prevent any lower dust loading than measured by SRI, the cold side extraction should be taken from Unit 4. If Unit 5 must be used, then use the east side outlet duct.

2.3 Unit 6 Hot Side Extraction

The original test plan included the possibility of hot side flow extraction from Unit 6 at the Crist plant. However, for Unit 6, the economizer outlet and the air preheater are coupled very closely together with ducts that include a 90° turn at the boiler outlet and a short offset transition duct to the air heater duct location. The measured data taken through two ports is very non-uniform for dust loading, velocity, temperature at low load, and NO/NO_x at high load as shown by the data spread from a total of eight readings taken through two ports:

Parameter	High Load		Low Load	
	Max.	Min.	Max.	Min.
Velocity (fps)	88.1	48.9	50.2	27.8
(% V_{AVG})	+38%	-23%	+35%	-25%
Dust Loading (gr/acf)	3.11	0.93	1.77	0.80
(% Avg)	+96%	-41%	+59%	-28%
Temperature (°F)	737	724	635	552
NO Concentration (ppm)	865	760	389	363
NO_x Concentration (ppm)	913	815	457	414

At least two of these parameter variations with load would make it undesirable to extract pitot plant flow from this location on Unit 6:

1. The dust loading level at individual point values, the spread between maximum and minimum, and the location of maximum and minimum values changes significantly from low to high load.

2. The concentration of NO and NO_x change by a factor of two from low load to high load.

This will mean that the pilot plant reactors on long term testing will see a wide range of conditions as the Unit 6 boiler load changes. This would be undesirable from the standpoint of interpreting and drawing conclusions from the pilot plant test data. These same problems do not exist at the Unit 5 hot flow extraction station.

Therefore, it would appear to be undesirable to use hot extraction flow from Unit 6 for the SCR Pilot Plant because of the following reasons:

1. The duct arrangement is too close coupled to produce a uniform flow pattern.

2. The test data shows wide variations of velocity and dust loading at either of the operating conditions tested.

3. The test data shows significant changes in dust loading and NO_x concentration level when load is changed.

4. There is no other hot side location for Unit 6 at which to get a better extraction of flow for the SCR Pilot Plant.

EXHIBIT 3.1-C

DUCTWORK HEAT TRACING

Zylinderheizkörper

Anwendung:

Zum Beheizen von Formen und Werkzeugen, besonders der Zylinder von Spritzgießmaschinen.

Auch die Beheizung von Behältern, Rohren oder anderen Apparaten ist möglich.

Die glimmerisolierten Heizkörper können bis zu 3,5 Watt/qcm Oberfläche belastet werden und die Arbeitstemperatur sollte 300° C nicht überschreiten.

Soll die Wärmeabstrahlung nach außen verringert werden, kann der Zylinderheizkörper mit einem Asbest-Wärmeschutzmantel versehen werden. Dieser Schutz genügt im allgemeinen.

Auf Wunsch kann auch ein Luft-Wärmeschutzmantel angebracht werden. Allerdings vergrößert sich dadurch der Heizkörper-Außendurchmesser um ca. 40 mm. Es muß vorher geprüft werden, ob genugend Einbauraum zur Verfügung steht.

Wenn auf Zylindern mehrere Heizkörper nebeneinander angeordnet sind, wird empfohlen, die Zylinderheizkorper in spreizbarer Ausführung zu wählen.

Hiermit kann jedes einzelne Heizband, ohne die anderen abnehmen zu müssen, ausgewechselt werden.

* Der im Bild ersichtliche Gerätestecker nach DIN 49490 ist nur noch für Export zulässig.

Nach VDE wird der Heizkörper mit einem Gerätestecker, 3polig, nach DIN 49458 gefertigt.

Montage-Hinweise:

Für die Lebensdauer des Heizkörpers ist ein sorgfältiges Aufspannen und pflegliche Behandlung ausschlaggebend.

Die Zylinderheizbänder müssen an allen Punkten der Innenflächen fest angespannt anliegen.

Unter dem Heizband dürfen sich keine Bohrungen oder Nuten befinden. Hierdurch kann die erzeugte Wärme vom Heizkörper nicht abgeführt werden. Es entsteht ein Wärmestau und dieser führt zur Zerstörung der Isolation. Die Folge ist ein Kurzschluß, der zur völligen Zerstörung des Heizbandes an den betroffenen Stellen führt.

Lassen sich Hohlräume nicht vermeiden, so muß der Heizring mit einem Wärmeleitblech versehen werden.

Auf glatter Zylinderfläche muß das Heizband ebenfalls fest und vor allem gleichmäßig anliegen.

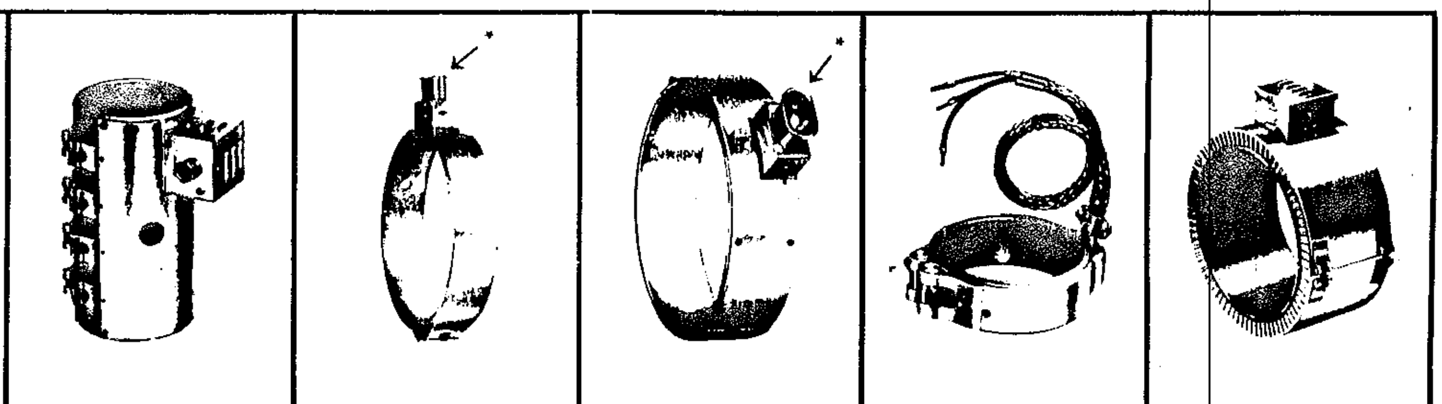
Zuerst die Spannschrauben mäßig nachziehen. Dann ganz leichte, zum Verschluß hintreibende Schläge mittels Gummihammer ausüben. Hierauf die Schrauben ganz fest anziehen. Einige Minuten nach dem Anheizen nochmals nachziehen.

Mit besonders langer Lebensdauer belohnt es der Heizkörper, wenn er, nachdem der Spritzzylinder die endgültige Arbeitstemperatur erreicht hat, nochmals nachgezogen wird.

Leider ist es noch nicht gelungen, die Heizbänder als Normtypen zu liefern. Die Vielzahl von Anwendungsgebieten erfordert spezielle Anpassung und Ausführung.

Nach Zeichnung oder Skizze fertigen wir jeden technisch möglichen Heizkörper.

erge ELEKTROWÄRMETECHNIK FRANZ MESSER
8563 Schnaittach · Hersbrucker Straße 31
Telefon 09153/644 · Telex 0624121 erge d



DUCTWORK HEAT TRACING
(SIGMA)

us ergibt sich, daß die Kontaktfläche bei einer Funktionshöhe von nm und einem Kanalabstand von 7 mm (9,5/7) gegenüber einem 5-Stein um 21%, gegenüber einem 12/7,5-Stein sogar um 34% er ist.

eigt sich somit, daß mit zunehmender Funktionshöhe der Keramik-e die am Zylinder anliegende Mattenoberfläche rapide abnimmt. Värmeübertragung geschieht daher, anstatt durch die verlustarme neleitung, in immer stärkerem Maße durch die verlustbehaftete nestrahlung. Außerdem sind die Kontaktflächen bei einem Heizkör-nit höheren Steinen (bei gleicher Heizleistung) einem höheren Wär-ırchfluß ausgesetzt als bei einem Heizband mit niedrigeren Steinen. rührt daher, daß dieselbe Leistung wie beim kleinen Stein über durch weniger Berührungspunkte, kleinere Fläche übertragen wer-muß. Somit erhöht sich auch die Lebensdauer eines Heizbandes ı,5/7 mm-Verhältnis.

Funktionshöhe von 9,5 mm ermöglicht also eine erheblich bessere enabstufung der Heizmatte und somit auch eine günstigere Anpas-an den vorgegebenen Durchmesser. Die Folge sind mehr Reihen miksteine und somit mehr Berührungspunkte und eine größere, am der anliegende Mattenoberfläche, sowie ein kleinerer Spalt.

ıroße kontaktierende Mattenoberfläche wird weiterhin auch durch ufteilung der Kanalabstände in 7 mm-Schritte erreicht. Hierbei ist feinere Breitenabstufung des Lieferprogrammes und eine bessere herung an die vom Kunden gewünschte Sollbreite möglich, als es inem größeren Kanalabstandsraster wäre. Somit erklärt sich auch eutlich geringere Mattenbreite der 11/7,5 und 12/7,5-Steine in Ta-2.

rtige Matten können hier nicht breiter sein; durch Hinzunahme ei-veiteren Kanales würde die Matte 120 mm breit, hinzu kämen dann seitlich Bleche und Zacken von ca. 4 mm Gesamtstärke. Es ergäbe also eine Gesamtbreite des Heizbandes von 124 mm, was die ver-e Höchstbreite von 122 mm jedoch überschreiten würde. Damit ·kt also der 7 mm-Kanalabstand eine breitere Matte und daher auch größere Gesamt- und Kontaktoberfläche.

so wird durch das 7 mm-Raster eine größere Anzahl von Heizka-ı ermöglicht, somit wird auch eine gleichmäßigere Temperaturver-ıg über die Gesamtbreite erzielt als bei größeren Rastern.

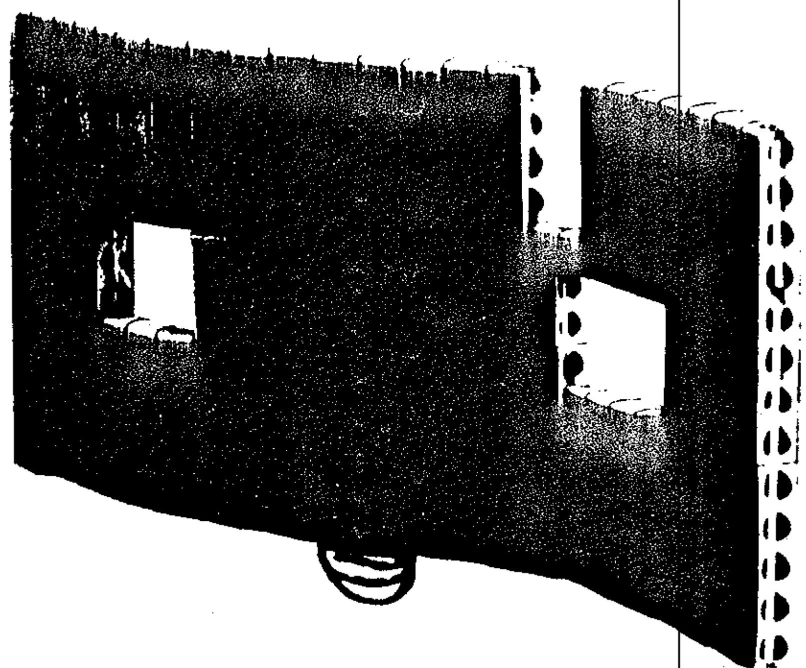
eramik 9,5/7/8.5 besitzt eine geringere Dicke, was ein geringeres nen der Heizmatte bewirkt.

le 2: **Rauminhalte von Keramikmatten**

nik- (mm)	Funktions-höhe (mm)	Gesamt-volumen (cm³)	Reines Keramik-volumen (cm³)
	9.5	547,73	366,38
	11.0	556,88	410,55
	12.0	546,75	403,08

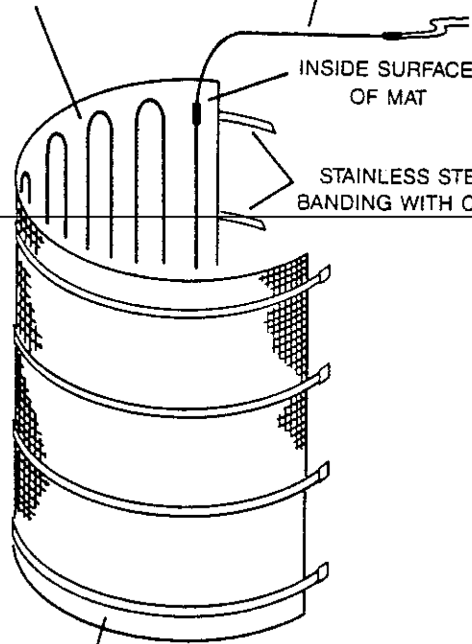
Hieraus ist zu ersehen, daß eine Heizmatte aus den MEFLEX-Keramikbausteinen trotz ihrer großen Oberfläche eine geringe zusätzlich zu erwärmende Masse besitzt, was außerdem eine Abkühlung in den Heizpausen bei Regelbetrieb begünstigt. Weiterhin ist die Keramikschicht zwischen Heizleiter und Zylinder um 20% dünner als bei vergleichbaren Steinen, was einen sehr schnellen und wirtschaftlichen Wärmetransfer von der Heizspirale zum Zylinder gewährleistet.

Somit ermöglicht diese Keramik den Aufbau von wirtschaftlichen, preiswerten und vielseitig verwendbaren Heizkörpern hoher Lebensdauer.



Weitere Anwendungsgebiete des ERGE-MEFLEX-Keramikheizkörpers:

- Keramikrahmenheizkörper, z. B. für Kunststoffpreßformen und Werkzeuge
- Keramikflachheizkörper, z. B. zur Beheizung glatter Maschinenteile, für Vorwärmplatten zur Klebstoff-Verarbeitung
- Keramikflächenstrahler, z. B. als Infrarotstrahler für Folientiefziehanlagen
- Keramikmattenheizkörper zur Beheizung aller gewölbten oder rauhen Oberflächen



Typ. mat heater

MAT HEATERS

TRASOR "MAT" heaters can be furnished to easily fit the walls of a tank, vessel, drum, or shaped to fit over a pump or many complex configurations. Construction is of a stainless steel cloth with heating cable permanently mounted on the inside surface. Size can vary from just a few square feet to several hundred square feet. They give uniform heating, with a wide range of watts per square foot available. Equipped with incoloy sheath heating cable, the mats can withstand very corrosive and high temperature environments. Incoloy cable offers exceptional resistance to readucing acids, oxidizing chemicals and chloride-ion stress-corrosion cracking. Standard incoloy sheath heating cable constructions can operate continuously at temperatures to 1000°F, and with the unit end cap of welded construction, unit sheath temperatures can withstand 1500°F. In less corrosive and extreme temperature conditions, copper heating cable can be furnished.

One of the greatest advantages of the mat heaters, is the minimal labor required for installation. They are relatively easily handled, with an average weight of only .6 lbs/sq. ft. To insure a snug tight fit, the mats can be furnished with fastening bands that are factory installed. After the bands have been secured, the heating cable is safely protected by the stainless cloth.

VESSEL WALL HEATING MATS CAN:

Maintain the contents at a given temperature by offsetting ambient heat losses.

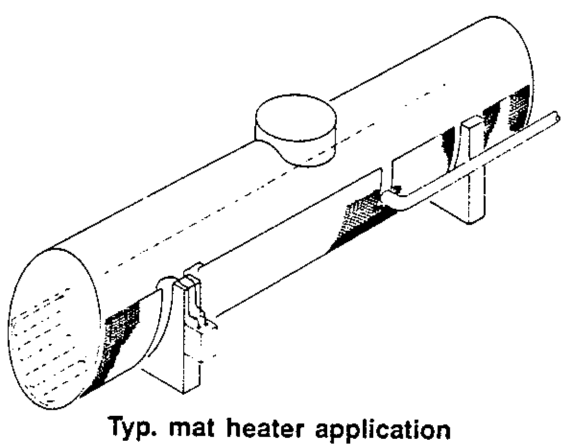
Be provided with higher heat, or dual-heat capabilities to compensate for start-up conditions.

Stabilize internal process conditions by eliminating the condensation of saturated vapors on the inner surface of outer non-wetted surfaces.

Eliminate any build-up that can occur due to residues being deposited in the condensation process.

Eliminate internal maintenance that could be required if residue build-up is a problem.

Reduce process heat input by eliminating condensation & outside wall losses.



Typ. mat heater application

Trasor CORP.

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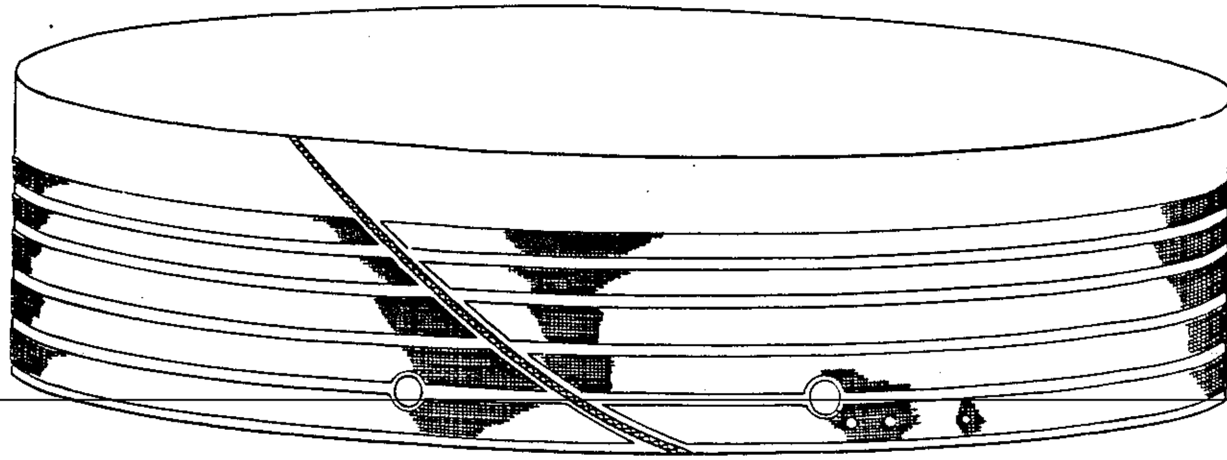

Heating a 200′ diameter storage tank

TRASOR has furnished "MAT" heaters for the side walls of a 200′ diameter Bunker C storage tank similar to that in figure C. Allowing for changing liquid levels, the heated area was divided into seven horizontal zones. Each zone required six 100′ long mats, 2′, 3′ & 4′ in width. The mat design allowed for the stairs and all nozzles. Each zone was separately controlled.

The life expectancy of a TRASOR heating mat is unlimited. Often, the mats have been removed from one system and reused on another. Being completely of metal & mineral construction, the units will not age as with organic systems.

For installation details see TRASOR bulletin P-115 & P-121.

MAT CONTROLLERS

The surface being heated can be monitored and the temperature controlled by using a thermostat or thermocouple controller. The thermocouple can be furnished attached to the mat, and where averaging may be desired, two, three, or four thermocouples can be furnished.

SLAB HEATING

TRASOR slab heaters use the same heating cable as with the above mats, but the cable is mounted on concrete reinforcement mesh. From parking lots to airplane hangers, the mats have been used to heat slabs for snow melting and comfort heating. The slab heaters are U.L. listed and are shown in detail on bulletin P-117.

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INSTALLATION AND OPERATING INSTRUCTIONS FOR TRASOR HEATING MATS

Each mat heater must be inspected and tested to insure that it has not been damaged during shipment or installation. These requirements are described on TRASOR bulletin No. P-115. Mat heaters should be installed in accordance with the plans, specifications and the following instructions.

MAT HEATERS

TRASOR mat heaters are made of a welded stainless steel cloth with TRASOR heater units permanently attached to the inside surface. Exiting from the side of the mat, the cold section is used to connect the mat to the power source. The mat is equipped with stainless steel banding for fastening the mat to a surface or wall. See figure 1. Each mat heater is rolled and packaged in a sonotube. The tubes open from one end and the rolled mats are easily removed.

Figure 1 — Typ. mat heater

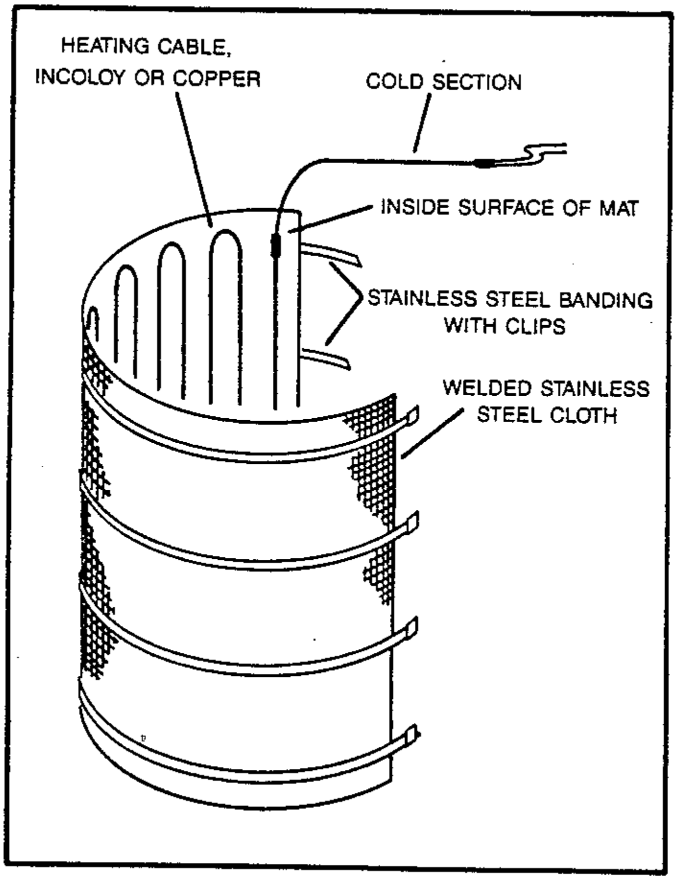
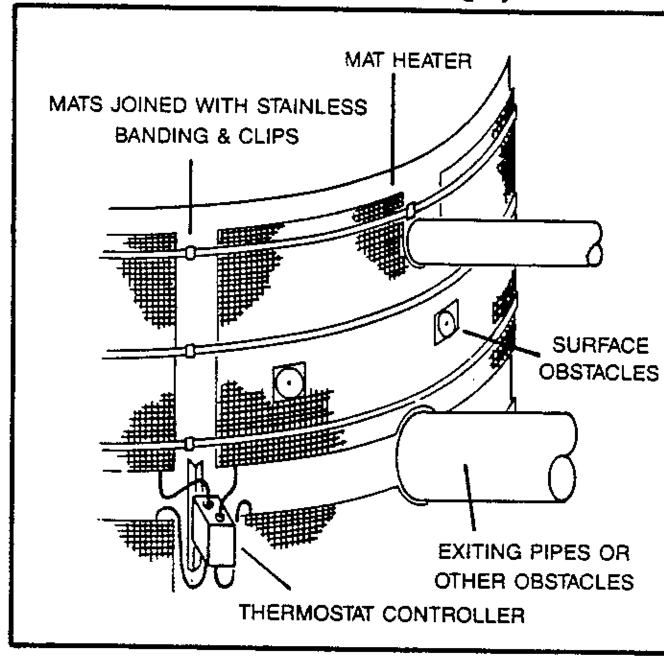


Figure 2 — Typ. vertical wall heating system



HEATING VERTICAL SURFACES

Typical heating of a vertical surface wall is shown in figure 2. This figure shows how common obstacles are encountered. The mats should be unrolled as they are installed, with the stainless cloth on the outside, while the heating cable is protected on the inside surface of the cloth. These mats are relatively easily handled, with an average weight of only .6 lbs/sq. ft. When long mats are being installed, Nelson weld studs should be used approximately every 5 feet so that the mat can be temporarily hung into place. See figure 4 & detail A. When encountering obstacles, the mats are provided with cutouts and banding as shown in detail A. If unexpected obstacles are encountered, the mats can be cut with wire cutters and the cable can be easily repositioned on the mat. All mats are designed and supplied with drawings to avoid such instances. After the mats are hung into place, they should be secured with stainless steel banding. In most situations, the mats will be supplied with banding already secured to the mat, which aids in fast installation. A pipe banding tool should be used to tighten the bands. When mat ends do not meet, banding stud plates should be used. The plates are bolted to a threaded weld stud that has been welded to the wall surface. See figure 3 & detail B.

Detail A — Banding around obstacles

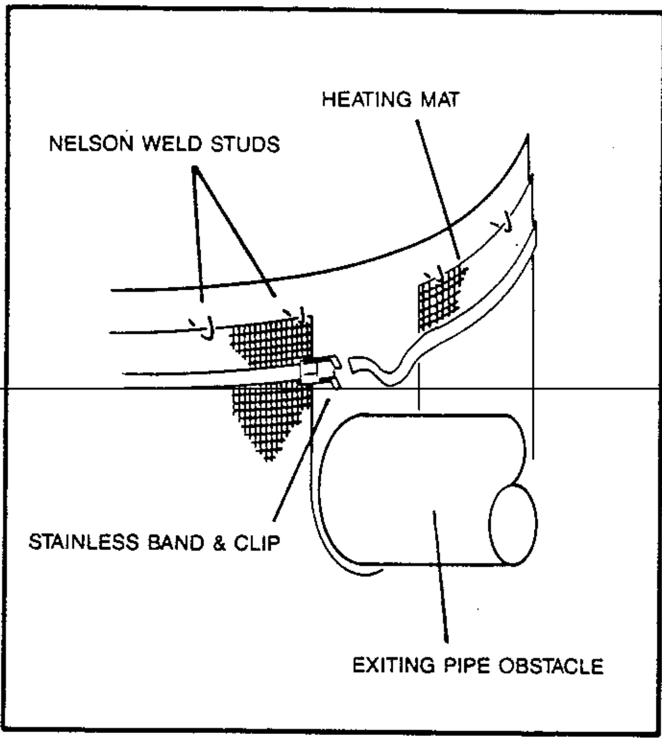
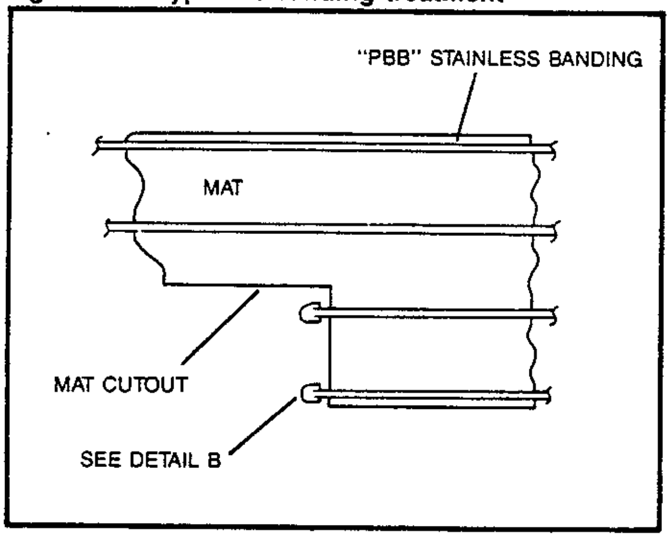


Figure 3 — Typ. mat banding treatment



Detail B — Banding stud plates

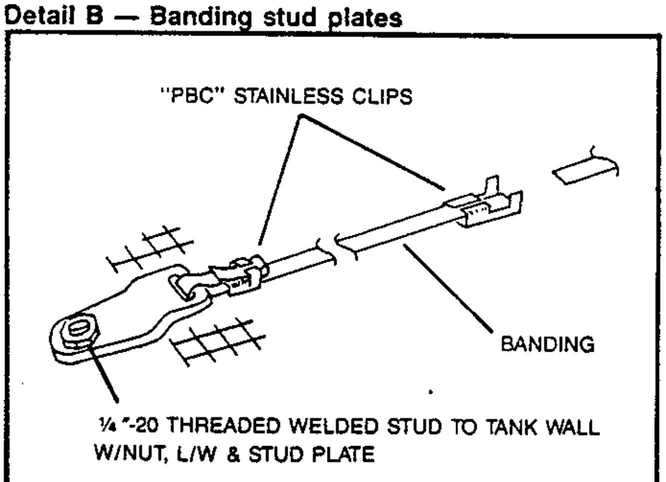
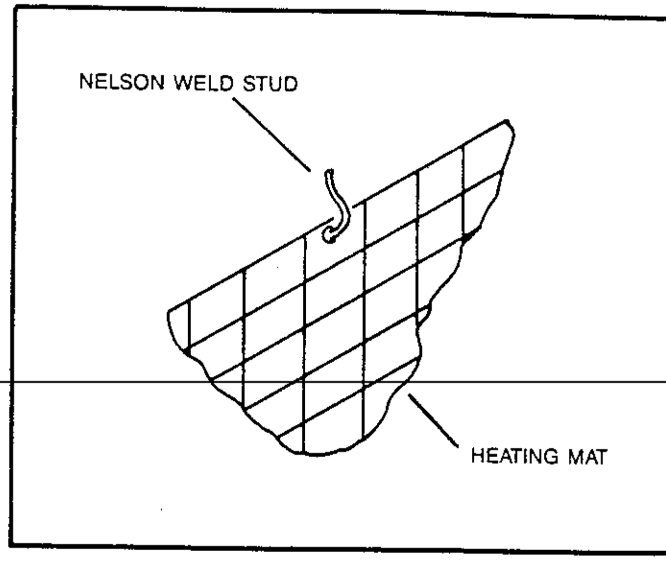


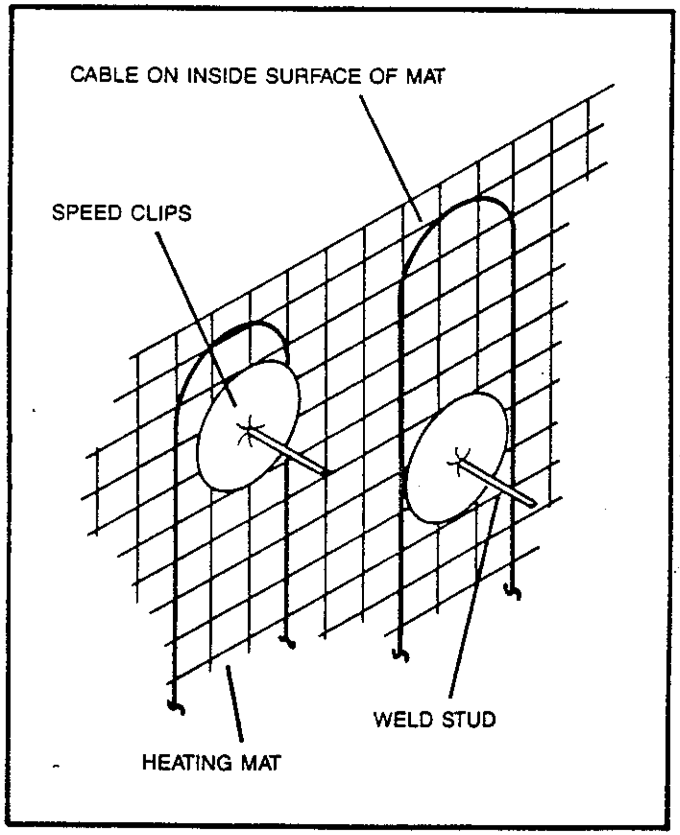
Figure 4 — Typ. Nelson weld studs



HEATING INVERTED SURFACES

When heating inverted surfaces, such as a tank or vessel bottom, where mats cannot be secured with banding. Nelson weld studs & speed clips can be used. Before the mats are installed, using a Nelson studgun, studs are set approximately every 18 inches. After the studs are attached, the mats can be held into place and secured firmly against the wall with the speed clips. If desired, longer studs can be used and the insulation can also be fastened in the same manner. See figure 5 & 6.

Figure 5 — Fastening mats to inverted surfaces



MEFLEX-Hochleistungs-Keramikheizkörper

ERGE-MEFLEX ist ein flexibler, anschmiegsamer Keramikheizkörper für Arbeitstemperaturen bis 800° C.

Er findet Anwendung in der Kunststofftechnik zur Beheizung von Spritzgießmaschinen, Extrudern und Blasköpfen. Aber auch im Autoklaven- und Sondermaschinenbau, für Laborgeräte und Folientiefziehanlagen wird er wegen seiner hohen Flexibilität, seiner langen Lebensdauer und seinen vielseitigen Anwendungsmöglichkeiten oft verwendet.

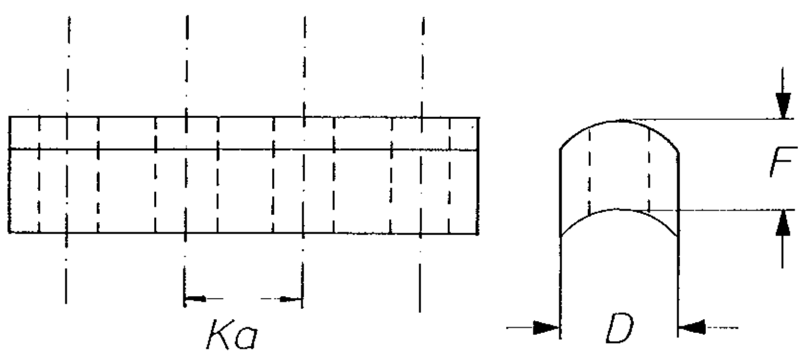
Der ERGE-MEFLEX-Keramikheizkörper war der erste in Deutschland hergestellte Keramikheizkörper.

Aufgrund seiner Spezialkeramik besitzt er dieselben thermischen Eigenschaften wie die früher verwendeten Heizkörper aus 99%-Aluminiumoxid-Keramik; er ist diesen gegenüber jedoch erheblich preisgünstiger. Seit seiner Einführung im Jahre 1965, bis heute, bietet er durch seine überlegene Konstruktion zahlreiche Vorteile gegenüber anderen Heizbandkonstruktionen.

Für Keramikheizkörper werden derzeit hauptsächlich drei Keramiksteintypen verwendet:

- Steine mit einer Funktionshöhe von 9,5 mm, einem Kanalabstand von 7 mm und einer Dicke von 8,5 mm (9,5/7/8,5-Stein).
- Steine mit einer Funktionshöhe von 11 mm, einem Kanalabstand von 7,5 mm und einer Dicke von 9 mm (11/7,5/9-Stein).
- Steine mit einer Funktionshöhe von 12 mm, einem Kanalabstand von 7,5 mm und einer Dicke von 9 mm (12/7,5/9-Stein).

Abb. 1: Maßbegriffe am Keramikstein



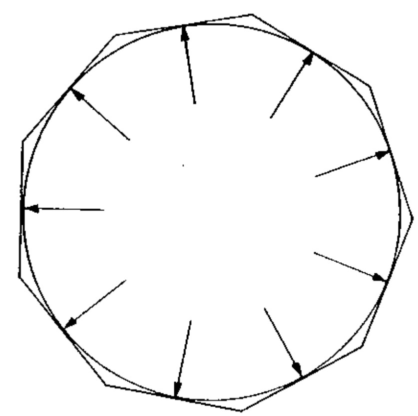
F Funktionshöhe   Ka = Kanalabstand   D = Dicke

Für ERGE-MEFLEX Keramikheizkörper finden ausschließlich Steine mit einem 9,5/7/8,5 mm-Verhältnis Verwendung. Diese weisen gegenüber anderen Abmessungen erhebliche Vorteile auf, welche im Folgenden näher gezeigt werden sollen.

Die aufgeführten Werte und Ergebnisse wurden durch umfangreiche Versuche und Berechnungen am Beispiel eines Keramikheizbandes von 170 mm Durchmesser und 122 mm Breite (170 ∅ × 122 mm) gewonnen.

Der Aufbau der Keramikheizmatten bringt es mit sich, daß sie auf gekrümmten Oberflächen in jeder Steinreihe nur annähernd linienförmig (ca. 2 mm Höhe pro Reihe) kontaktieren.

Abb. 2: Anliegen der Keramikreihen einer Heizmatte an einem Zylinder (schematisch)



◀ Kontaktpunkte Stein/Zylinder

Dies ergibt aber für unterschiedliche Funktionshöhen auch unterschiedlich große Gesamtkontaktflächen:

Tabelle 1: Kontaktierende Mattenoberfläche bei ca. 2 mm hoher Kontaktfläche pro Stein (für ∅ 170 mm)

n	F (mm)	Ka (mm)	B (mm)	Kontaktierende Oberfläche (cm^2)	Strahlende Oberfläche (cm^2)
57	9,5	7	119,00	135,66	508,73
50	11	7,5	112,50	112,50	506,25
45	12	7,5	112,50	101,25	506,25

mit n = Anzahl der Berührungspunkte (= Anzahl der Reihen)
Ka = Kanalabstand (siehe Abb. 1)
B = Breite der Keramikmatte
F = Funktionshöhe

Figure 6 — Installing insulation on inverted surfaces

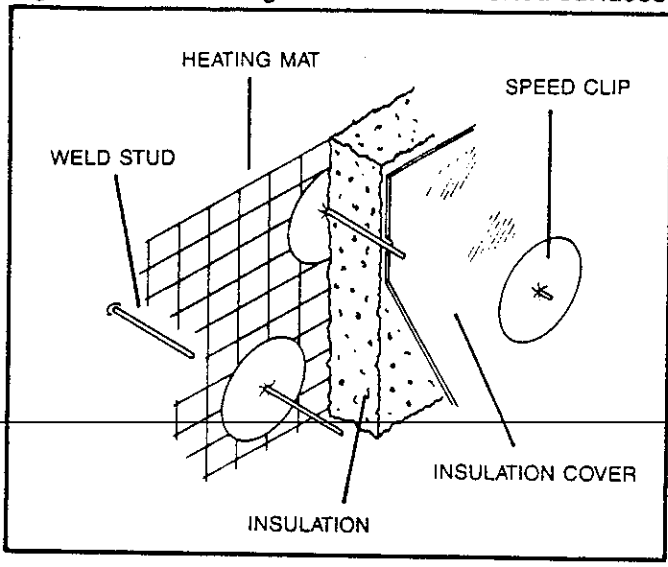


Figure 8 — Typ. mat feed arrangement

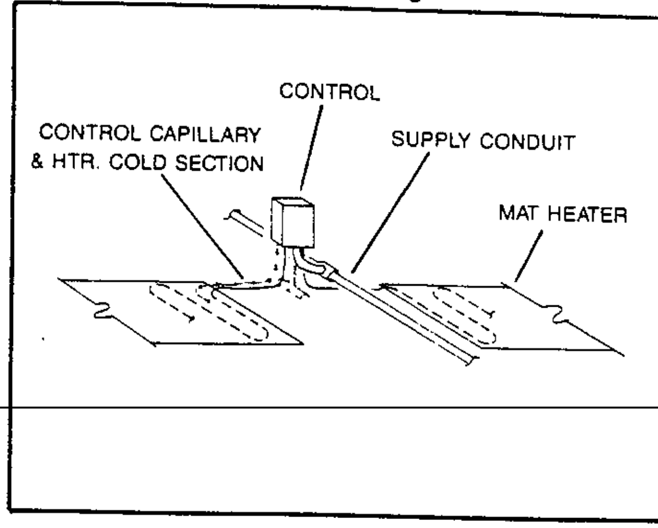
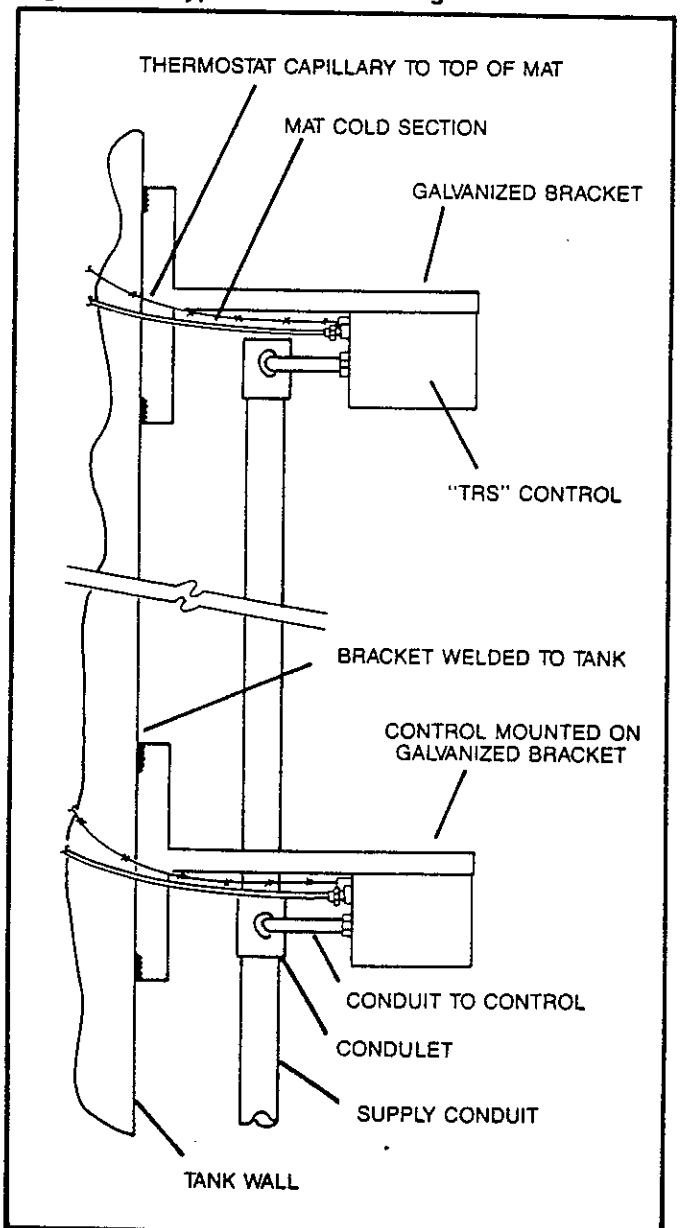


Figure 7 — Typ. control mounting

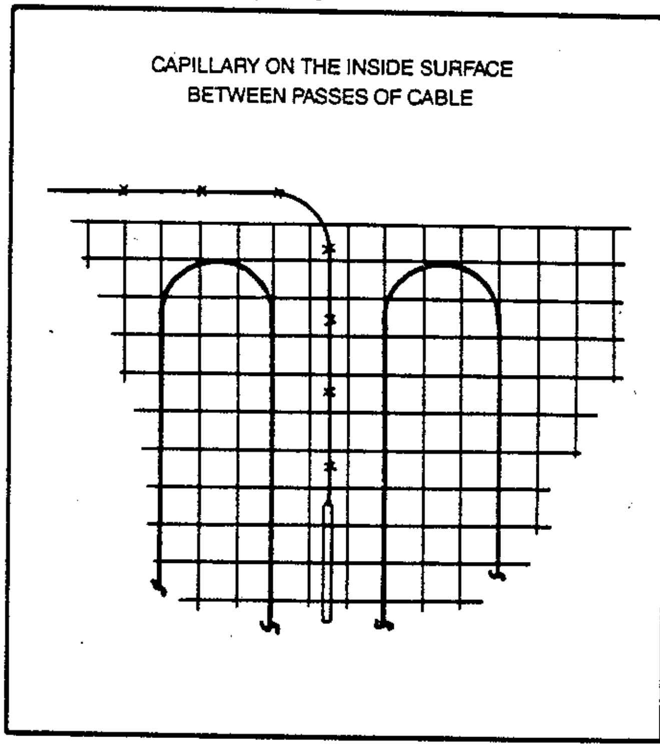


MAT CONTROLLERS

The surface being heated can be monitored and the temperature controlled by using a thermostat or thermocouple controller. Typical locating and mounting is shown in figure 7 & 8. The thermocouple can be furnished attached to the mat, and where averaging may be desired, two, three or four thermocouples can be furnished. The thermostat capillary & bulb should be protected against the wall surface under the cloth mat between passes of cable. See figure 9.

Controllers can be furnished mounted on galvanized brackets that can be easily spot welded to the vessel wall where required.

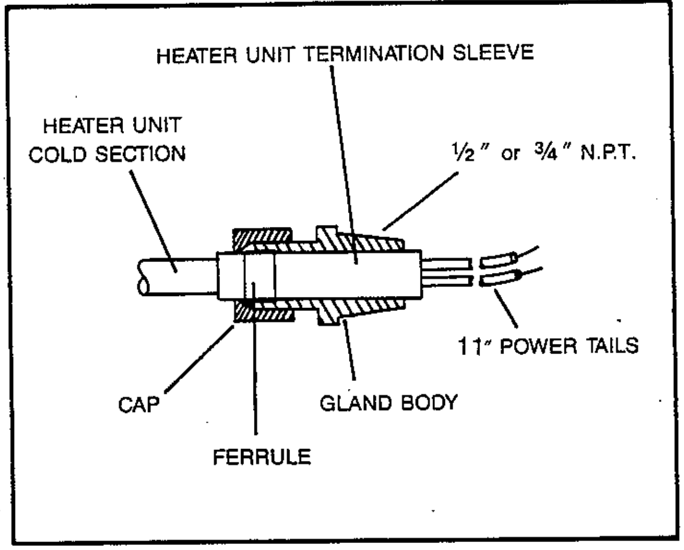
Figure 9 — Typ. capillary and bulb location



TERMINATION

The heating mat is equipped with cold section leads, which are available in any length to reach remote junction box locations. This cold section is a conduit system in itself for connection to the power source, and will not generate heat. Care must be taken not to damage this section, because it is not protected by the stainless cloth. Each unit is terminated with a brazed seal and furnished with a pressure fitting for attaching the cable end into a conduit hub. See figure 10.

Figure 10 — Typ. mat cold section termination



RECOMMENDED NELSON EQUIPMENT

101-260-100	12 GA. × 1″ Wire Studs
502-001-002	Med Foot
511-001-002	Spark shield
521-001-014	Morse taper adapter
500-001-153	Chuck
101-010-011	¼-20 × 1″ threaded stud
100-101-006	¼″ Ferrule
501-001-005	Ferrule grip ¼″
500-001-007	Chuck

If 400 Amp Lincoln, Hobart or equivalent D.C. welder is available use Nelson no. "NS-30" control. If the above is not available and 208, 230 or 460 VAC, 1ph., 60 Hz is available use the Nelson no. "TR-450B" controller with free wheeling diode and combination 50′ cable.

WARRANTY

TRASOR heating products have been manufactured and tested to quality standards. Each unit must be checked just prior to installation. Any unit found to be defective in material or workmanship at this point may be returned for replacement.

3.2 MAJOR EQUIPMENT

Table 3.2-1
Listing of Major Equipment in Area 100

Area	Description	Equipment No.
100	Host boiler duct extraction scoop	ES-101
100	Reactor train A flue gas takeoff	ES-102A
100	Reactor train B flue gas takeoff	ES-102B
100	Reactor train C flue gas takeoff	ES-102C
100	Reactor train D flue gas takeoff	ES-102D
100	Reactor train E flue gas takeoff	ES-102E
100	Reactor train F flue gas takeoff	ES-102F
100	Reactor train G flue gas takeoff	ES-102G
100	Reactor train H flue gas takeoff	ES-102H
100	Reactor train J flue gas takeoff	ES-102J
100	Main extraction line flow control damper	FCD-101
100	Economizer bypass flow control damper	FCD-102

4.0 AREA 200: FLUE GAS DISTRIBUTION HEADER TO REACTOR INLET

Area 200 is the area from the flue gas header to the outlet of the inlet duct for the SCR reactors. This area includes the flue gas extraction header, reactor train isolation dampers, electric flue gas heaters, flow venturi, air purge for startup and shutdown, and reactor inlet ducting. A list of Area 200 major equipment is provided in Table 4.2-1.

4.1 DESCRIPTION

4.1.1 Flue Gas Extraction Header

Common round pipe will be utilized for the flue gas ductwork, from the extraction scoop to the reactor inlets. Transition pieces also will be used where necessary for connecting to equipment on ductwork with rectangular interfaces.

There are two alternatives being considered for the take-offs from the flue gas manifold for the small reactors on high-dust service. Originally, and as still depicted on the layout drawings in this report (See Figure 4.1-1), each reactor would have its own take-off. However, an alternative which probably will be used is the use of a common extraction scoop for all five of these small reactors, as shown in Figure 4.1-2. The large reactors will still maintain individual take-offs, as shown in Figure 4.1-1, and the flue gas manifold will decrease in size after each take-off to maintain the duct velocity at 60 fps. The reactor take-offs from the manifold should be at an angle less than 90 degrees (i.e., 45 degrees). Therefore, standard Y piping components can be used for the large reactor manifolds. Long radius elbows should be used for 90 degree turns in all the duct work to the reactors. (Refer to Exhibit 4.1-A for information from DynaGen on take-off layouts.)

4.1.2 Isolation Dampers

A positive shutoff damper will be installed in each reactor train duct to allow for routine maintenance and to isolate the system from the host boiler during system upsets. Air-in leakage for the isolation dampers must be minimized, particularly for the large reactor trains.

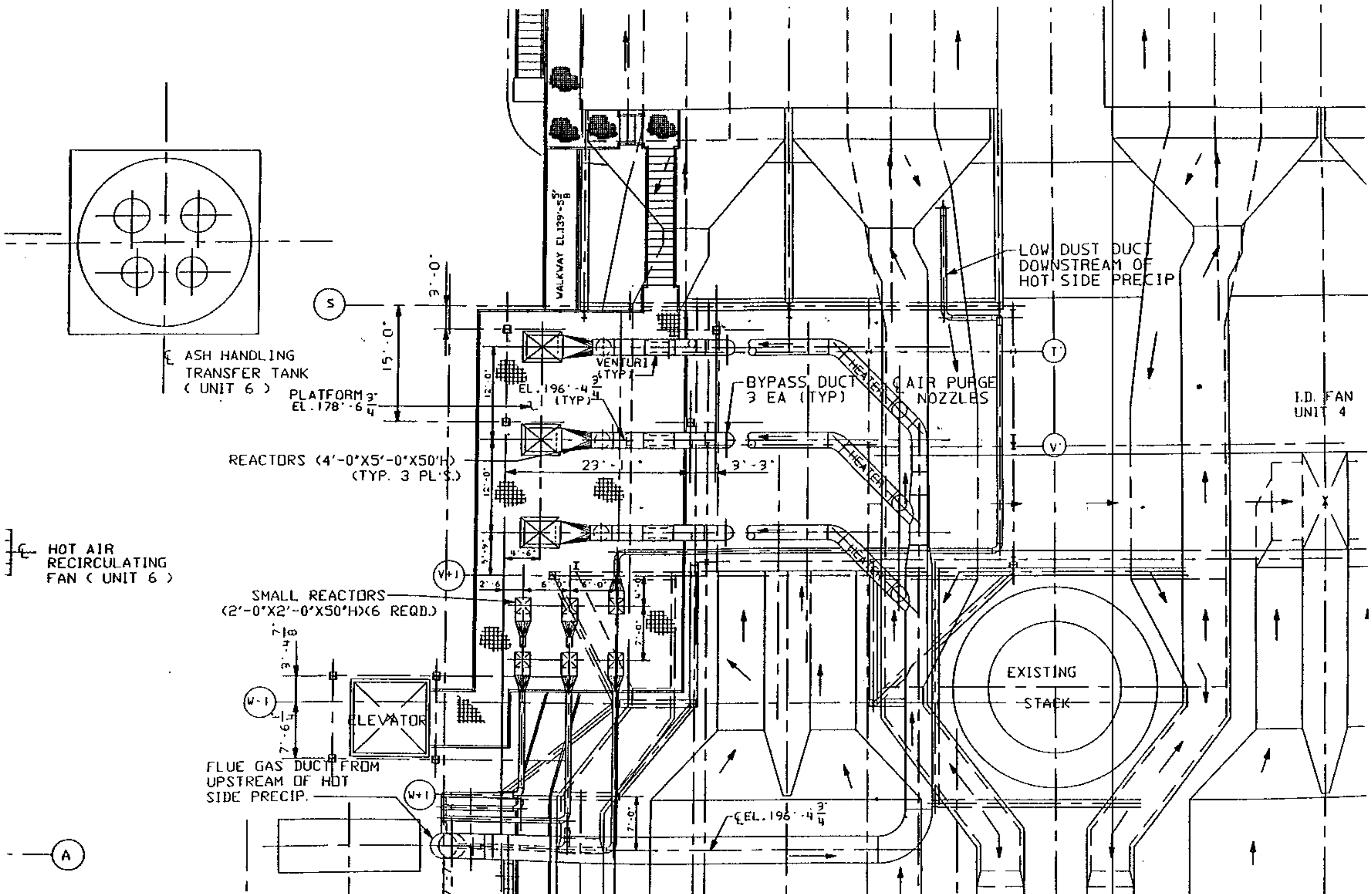
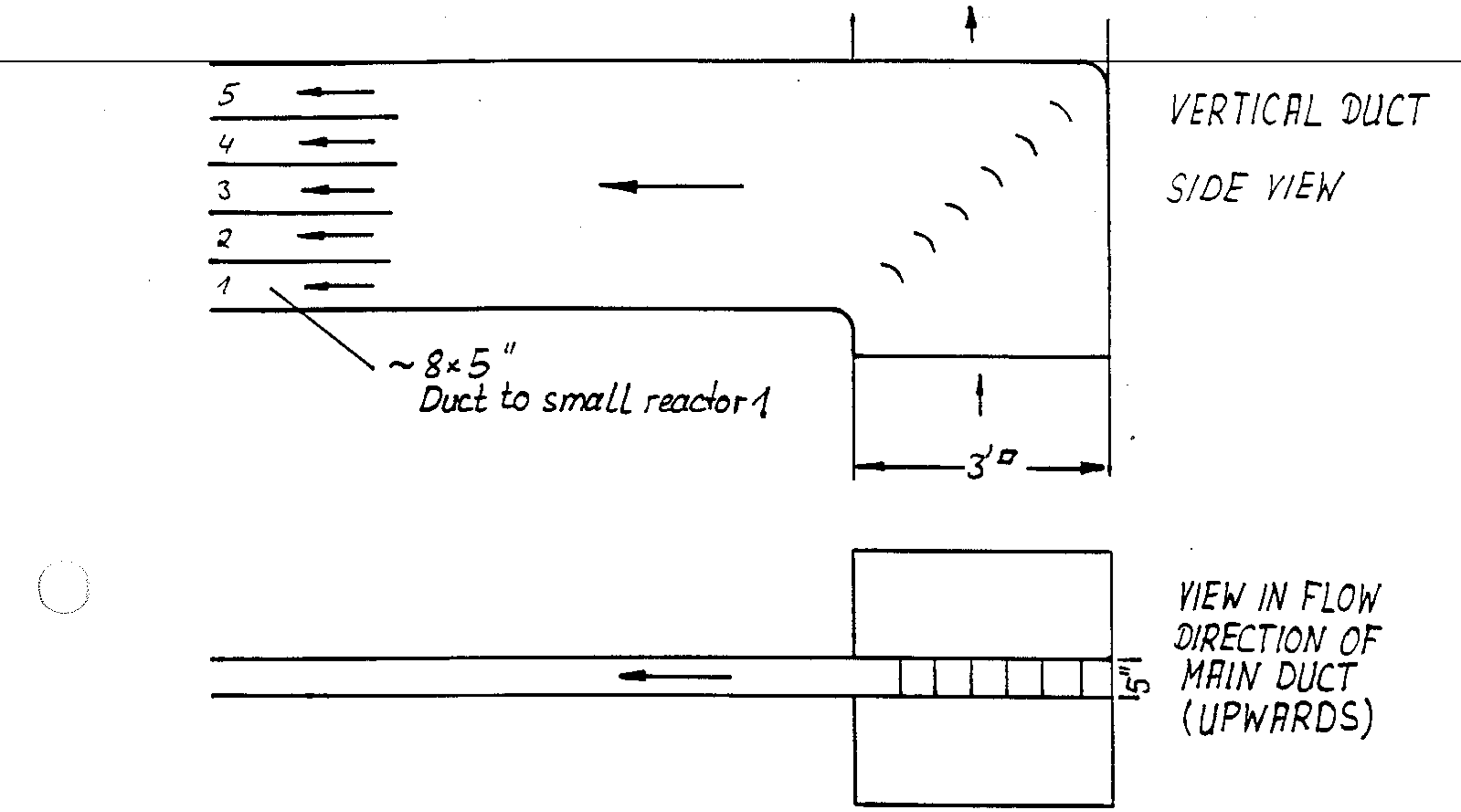


Figure 4.1-1. Drawing showing individual reactor take-offs.



acc. fairing behind scoop and guide vanes see also fig. 1.1.1

Figure 4.1-2. Common extraction scoop for small reactor.

4.1.3 Electric Flue Gas Heaters and Air Purge

Purpose

The flue gas electric heaters will be used to control the temperature of the flue gas entering each SCR reactor. Each reactor train will utilize an independently operated heater, or bank of heaters, to control the flue gas temperature for that particular reactor. The flue gas temperature coming out of the electric heaters will range from 620°F with heaters out of service to 750°F with maximum heater operation. Maximum heater loads will be calculated for a flue gas outlet temperature of 750°F when operating at the maximum flow rate, 7500-scfm for large reactors, and 600-scfm for small reactors.

The flue gas electric heaters will also provide a heat source to heat ambient air when purging the reactor of combustion gases or heating the reactor up during cold start ups. The ambient air purge allows controlled startup and shutdown of the catalyst, particularly when passing through the moisture and acid dewpoints. The flue gas electric heaters will be required to heat ambient air from a temperature of 30°F to 300°F when operating at the minimum reactor flowrate, 3000-scfm for large reactors, and 260-scfm for small reactors.

Size

The electrical heater loads were grossly estimated using the following formula:

$$kW = [CFM \times \text{Delta } T]/3000$$

Where: CFM is the flow rate of gas at standard conditions (70°F and 1 atm)
(Note: SCFM in this report is given at 32°F, 1 atm)

The large reactor flow ranges from a maximum of 7500-scfm to 3000-scfm with the design flow rate being 5000-scfm. Therefore, maximum electrical load for the large reactor heaters when heating flue gas would be approximately:

$$(7500)((460+70)/(460+32))(750-620)/3000 = 350 \text{ kW}$$

Maximum heater loads for heating ambient air for large reactor purge would be approximately:

(3000)((460+70)/(460+32))(300-30)/3000 = 291 kW

The small reactor flow ranges from a maximum of 600-scfm to 260-scfm with the design flow rate being 400-scfm. Therefore, maximum electrical load for the small reactor heater when heating flue gas would be approximately:

(600)((460+70)/(460+32))(750-620)/3000 = 28 kW

Maximum heater loads for heating ambient air for small reactor purge would be approximately:

(260)((460+70)/(460+32))(300-30)/3000 = 25 kW

Location

The electric heaters will be located in the ductwork upstream of the SCR pilot plant reactors. The inlet ductwork consists of round carbon steel or spiral wound pipe and will range in size from 24 in. diameter for the large reactors to 6 in. diameter for the small reactors. Provisions can be made for square or round mounting through custom or standard type flanges. See Figure 4.1-3 for a conceptual installation configuration.

The physical layout of the large reactor heaters is shown in Figure 4.1-1. The heaters will be mounted in a horizontal duct run with flue gas contact perpendicular to the heater elements. There is 10 linear feet of duct run in which the heater must fit.

Although the small reactor heaters have not been physically located, it is assumed that they will also be in a horizontally mounted duct.

The location of the heaters will be downstream of the air purge connection and upstream of the ammonia injection grid. This allows ambient air to be drawn across the heaters to allow reactor purging and heatup. Also, the ammonia is

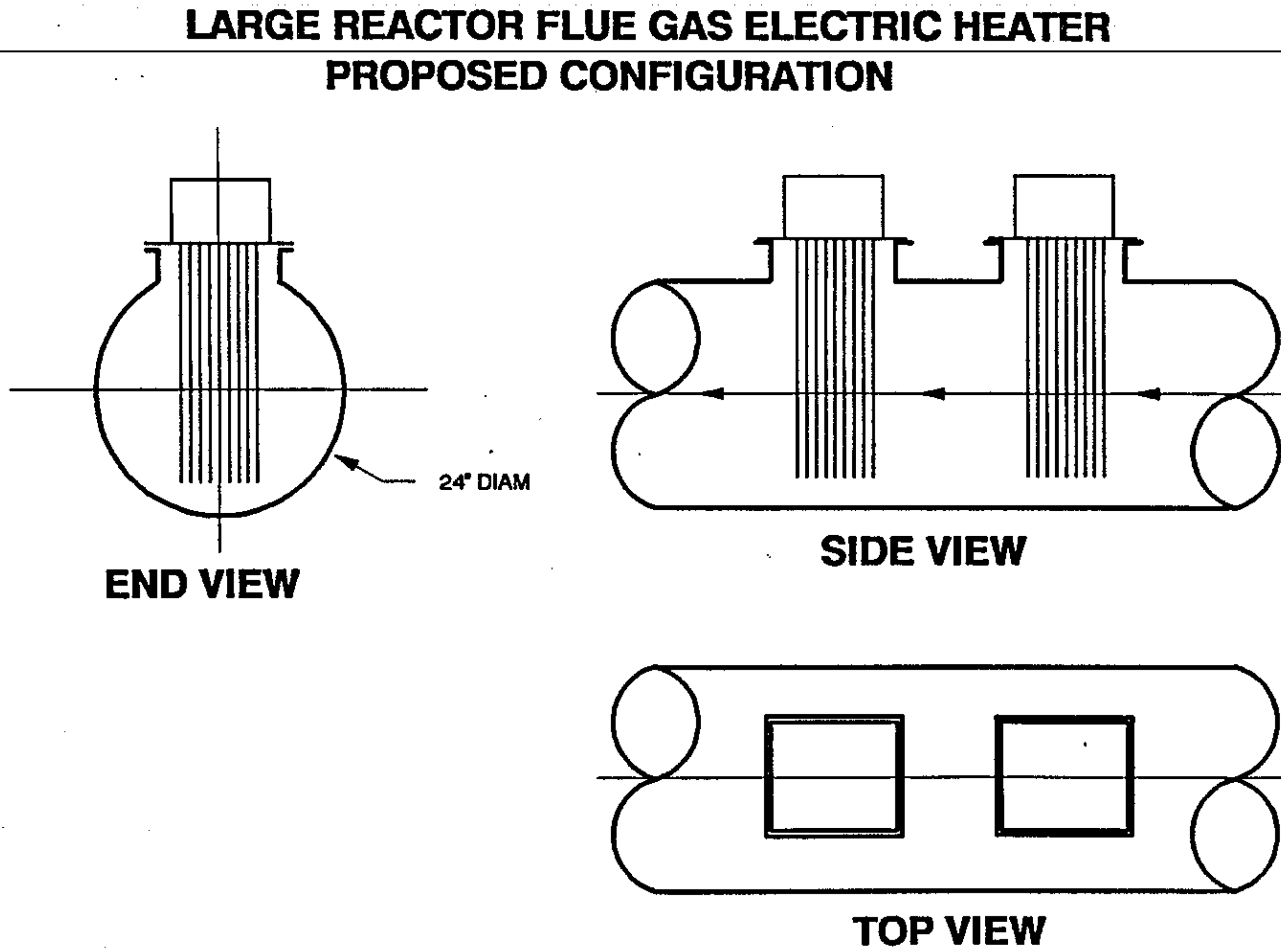


Figure 4.1-3. Conceptual illustration for electric heater.

injected downstream of the heater where it would not be subjected to high surface temperature elements and hence, thermally degrade to form NOx.

For both large and small reactors, the flue gas heaters may be a single heater, bank of heaters or staged heaters, whichever economically meets the required flexibility.

Operation

The flue gas electric heaters will be heating a dust-laden gas produced in a utility boiler. The flue gas temperature supplied to the electric heaters will vary between 620°F to 680°F depending on boiler load. The minimum temperature of the flue gas supplied to the electric heaters is 620°F by using an economizer bypass line.

The maximum required flue gas temperature leaving the electric heaters is 750°F. The typical operating design outlet flue gas temperature from the electric heaters is 700°F. Therefore, final heater size should be able to raise the flue gas temperature from 620°F to 750°F at the maximum flue gas flow rate.

Control

The flue gas electric heater control shall be capable of maintaining the bulk gas temperature to within $\pm$ 2°F of the desired setpoint. The pilot plant Distributed Control System (DCS) will output one (1) 4-20 MA DC signal to the heater controls. The heater(s) shall use silicon control rectifiers to control heat output based on the value of the 4-20 MA DC signal (4 MA = zero heater output and 20 MA = maximum heater output). The heater control shall be provided with overload protection, flow detection, and overtemperature protection.

Process Concerns

There are two process concerns related to the flue gas electric heaters. The first concern is the tendency of the heaters to oxidize SO_2 to SO_3. This side reaction takes place due to the catalytically active metallic surface of the heater element operating at high temperature. The surface temperature of the heater element is much hotter than the bulk gas temperature. Since SO_3 is undesirable to the pilot plant and downstream equipment, minimizing the conversion across the heaters is desired. The expected SO_2 and SO_3 concentrations in the flue gas are shown below.

Sulfur Dioxide (SO_2)	2200 - 3000 ppmv
Sulfur Trioxide (SO_3)	15 - 20 ppmv

One option which should be explored is the ability of vendors to furnish ceramic type heater elements rather than metallic alloy type heater elements. This would reduce the conversion rate of SO_2 to SO_3 since ceramic is less catalytically active than metal. A second option would limit the watt-density of the individual heater elements to less than 20 watts per square inch.

The other concern is fly ash erosion of the heater elements. The heaters will be subject to a fly-ash-laden flue gas. The ash loading, gain loading, and particulate distribution are in Table 4.1-1.

Electrical

The pilot plant has 480 volt, 3-phase, 60 hz power available for the electric heaters. The heaters will utilize high temperature cables to protect from overheating of wires and/or melting insulation. It is desired that overtemperature control be incorporated into the heater design to prevent the heaters from burning out when no flow conditions occur. External heater components should be enclosed in a NEMA 4, or 4X-type, enclosure for weather protection. The heaters should be electrically isolated from the pilot plant or host unit electrical supply to prevent any noise from causing problems in the upstream side of the electrical supply. The number of multiple heaters (or heater banks) shall be divisible by 3 to minimize phase distortions.

Table 4.1-1
Heater Inlet Conditions

	Large Reactor	Small Reactor
Flowrate (acfm)		
Maximum	17378 acfm	1390 acfm
Design	10975 acfm	878 acfm
Minimum	6585 acfm	527 acfm
Ash Loading (lb/hr)		
Maximum	225 lb/hr	18 lb/hr
Design	150 lb/hr	12 lb/hr
Minimum	90 lb/hr	7 lb/hr
Grain Loading (gr/acf)		
Maximum	1.59 gr/acf	1.59 gr/acf
Design	1.59 gr/acf	1.59 gr/acf
Minimum	1.51 gr/acf	1.51 gr/acf

Miscellaneous Requirements

It is desired that the flue gas electric heaters be furnished with changeable heater elements (vs welded elements) rather than replacing the entire heater. Provisions should be made to minimize the occurrence of ceramic insulator damage due to moisture or overheating. A flue gas electric heater furnished with a flange connection on each end to allow one to lift it into place is one idea under consideration. This is illustrated by Figure 4.1-4. Figures 4.1-5 and 4.1-6 show electrical hookup of the heaters. The flange to flange dimension for the large reactor should not exceed 10 ft. Small reactor heater dimensions are not yet defined.

Flue Gas Composition

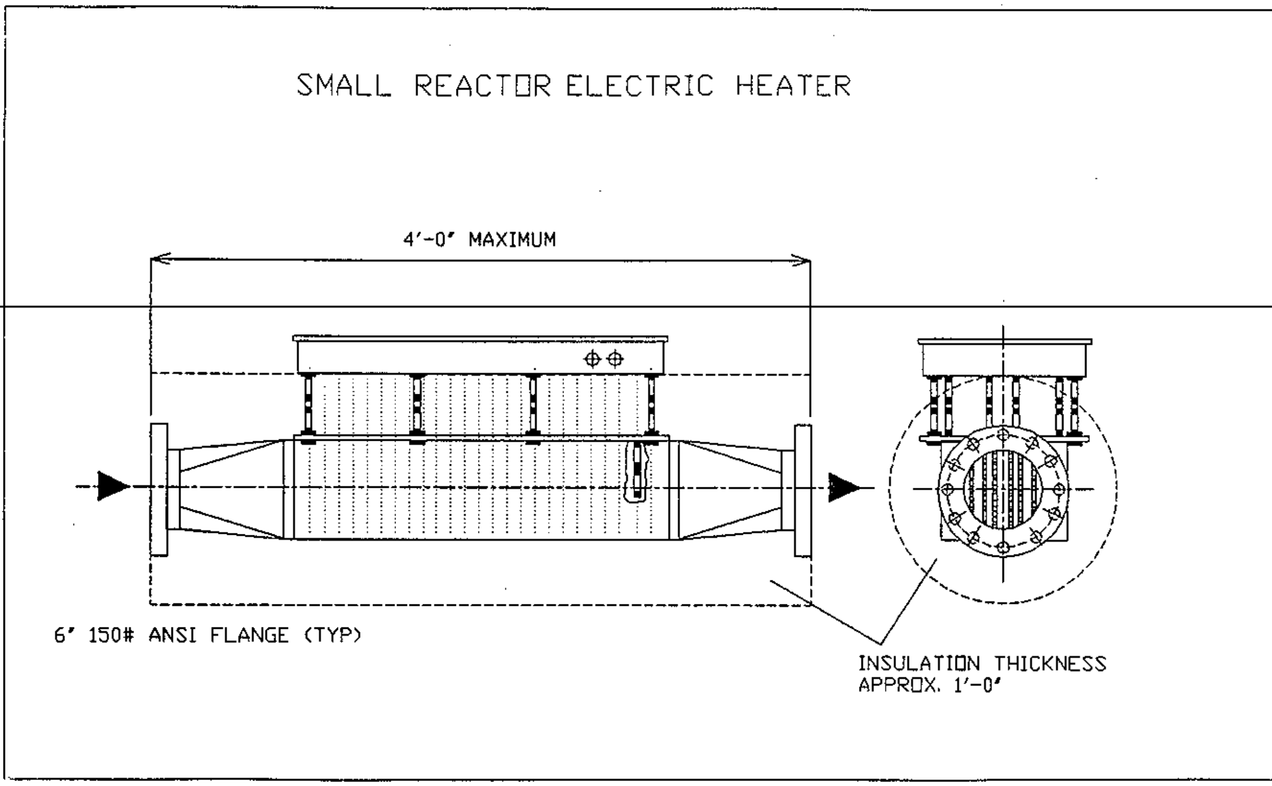
The predicted flue gas composition for the large and small reactors at maximum flow conditions are shown in Table 4.1-2.

Venturi

DynaGen has concurred that a venturi type flowmeter is a good choice for flow measurement for a high fly ash environment. A flow straightening grid should be installed ahead of the venturi flow meter to eliminate any swirls in the flue gas. These flow straighteners should be per ASME, AMCA and ASHRAE guidelines. Preliminary design assumes a non-calibrated venturi. Pressure taps will be provided by a piezometer ring, or averaging annulus, to increase accuracy. The rings will have an automatic air blowback system to periodically clean the taps of fly ash. See Figure 4.1-7 for a sketch of the venturi, and see Exhibit 4.1-B for information on flow measurement supplied by DynaGen.

4.1.4 Reactor Inlet Ducting

For the reactor inlet ducting design, DynaGen performed flow modeling tests with a 1/2 scale model of the inlet ducting for two alternative designs. Each alternative reflected the following changes from the original reactor inlet concept: a) change from a vertical inlet duct run to a horizontal duct run



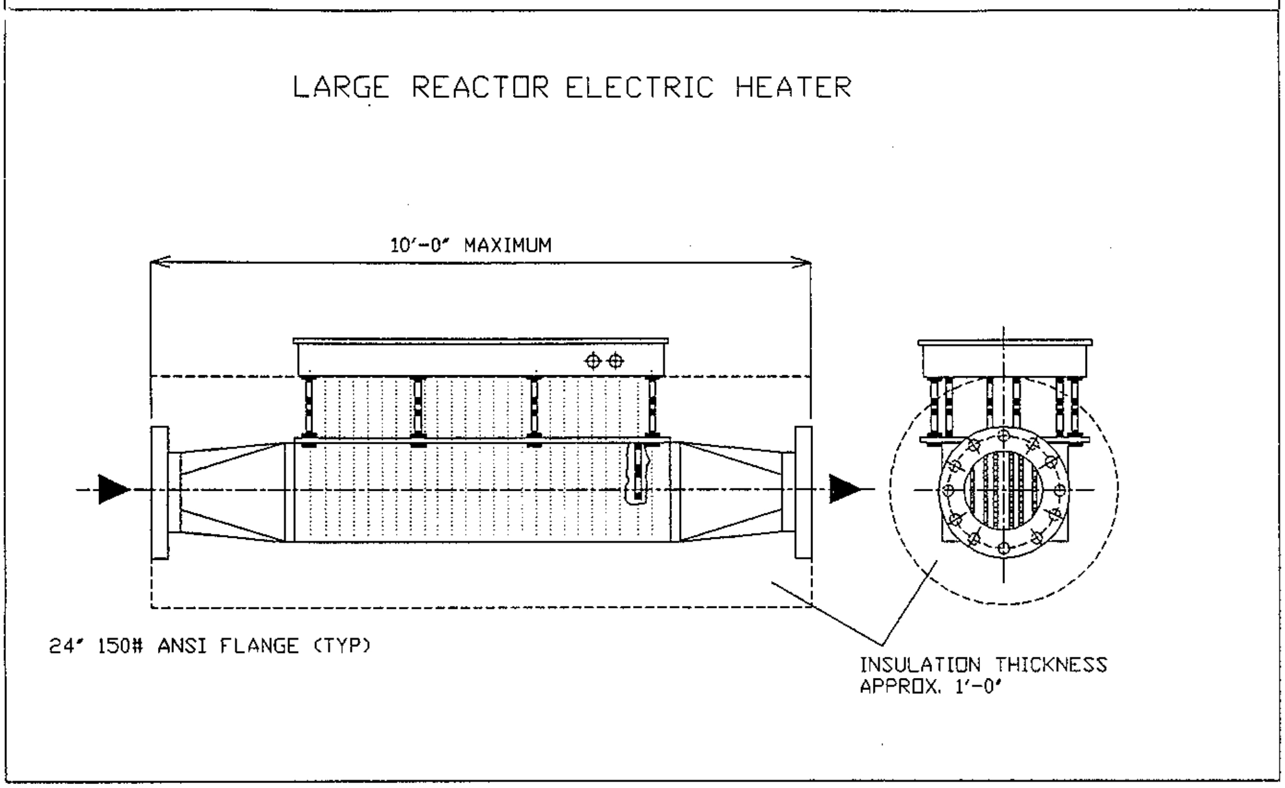


Figure 4.1-4. Flue gas electric heaters.

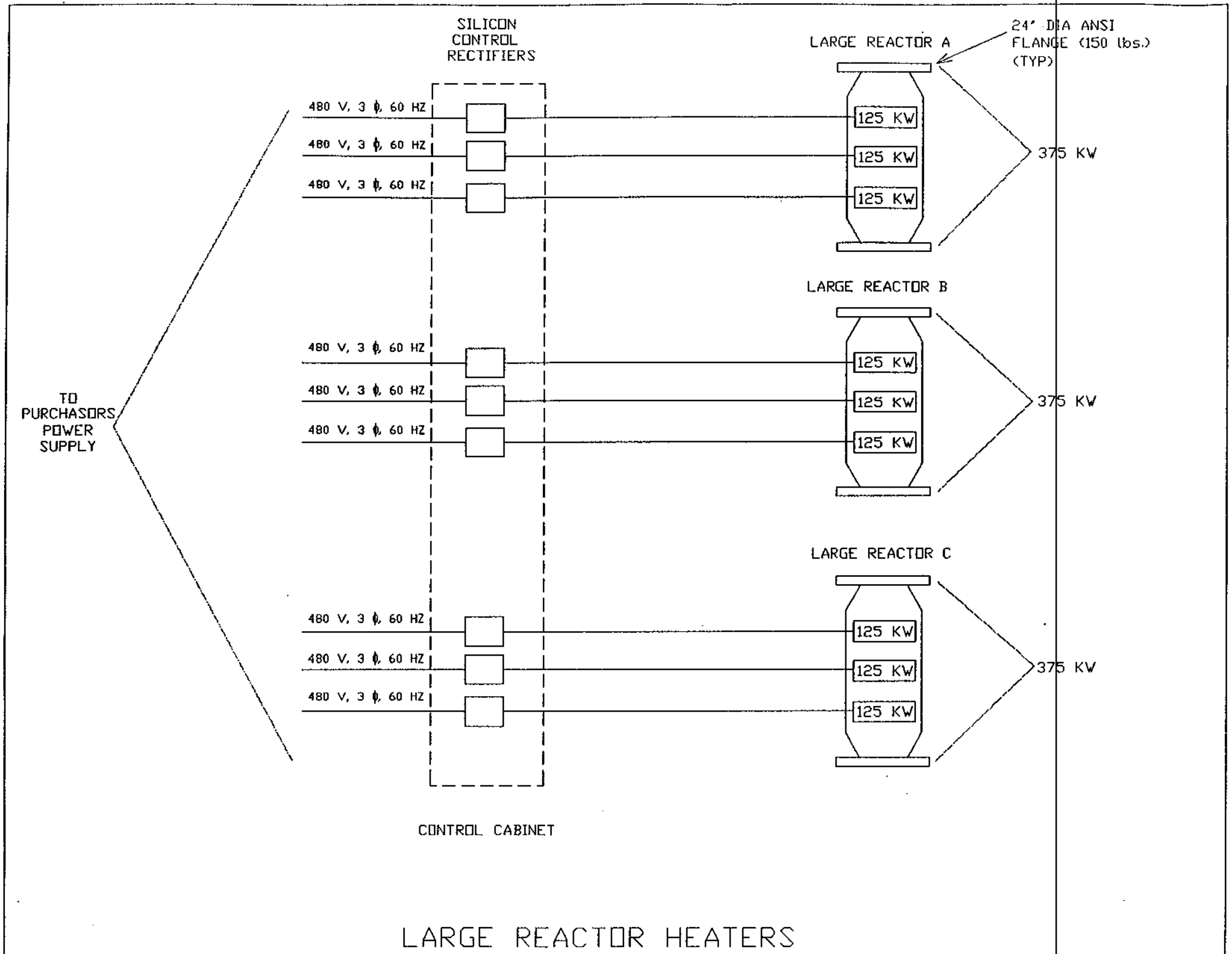


Figure 4.1-5. Sketch of electrical hookup for large reactor heaters.

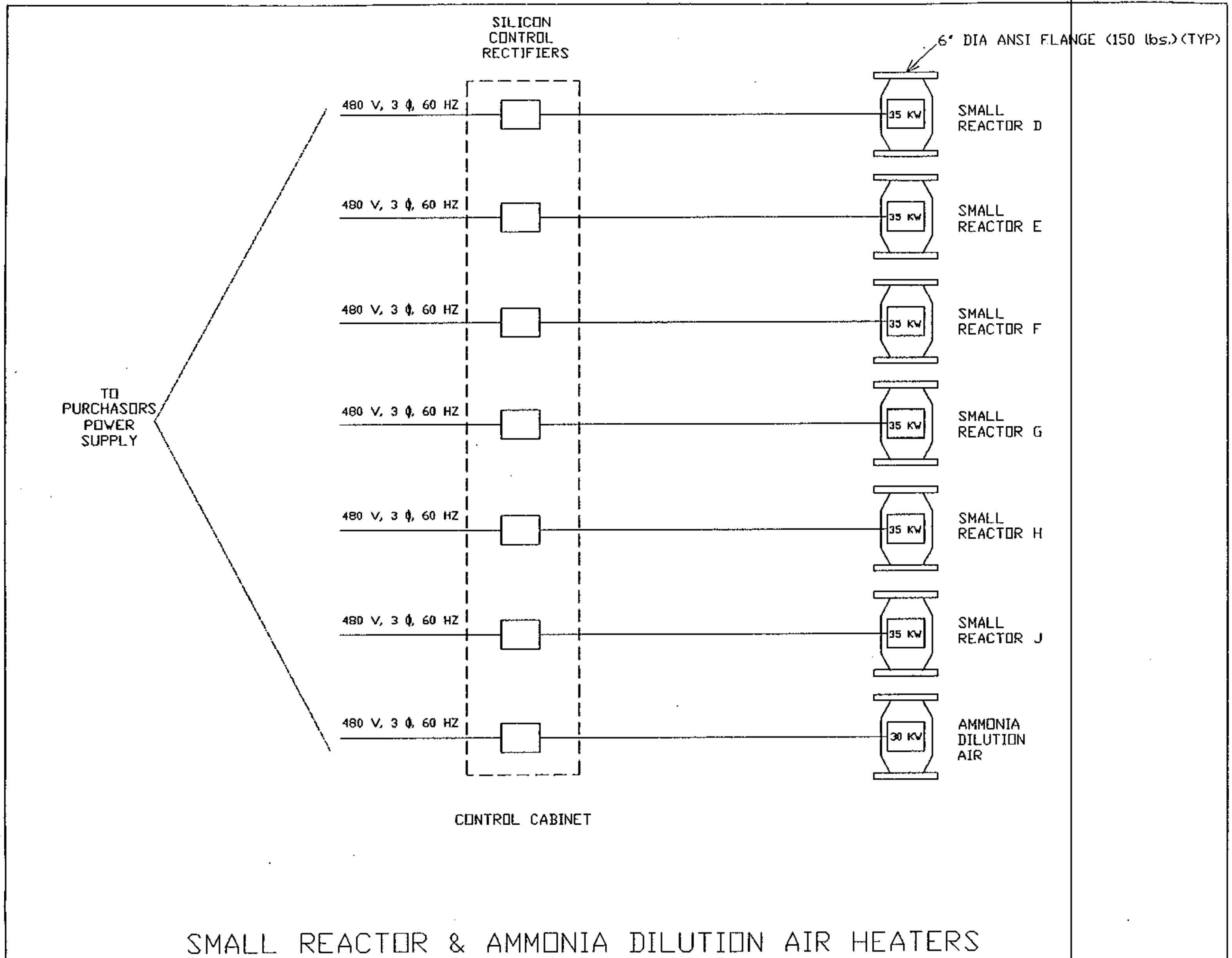


Figure 4.1-6. Sketch of electrical hookup for small reactor heaters.

Table 4.1-2

Flue Gas Composition At Maximum Flow Conditions

	Large Reactors (High Dust) Reactors A,B,C		Small Reactors (High Dust) Reactors D,E,F,G,H		Small Reactor (Low Dust) Reactor J	
Component	lb/hr	Weight%	lb/hr	Weight%	lb/hr	Weight%
CO_2	7643	20.57	611	20.55	611	20.69
O_2	1190	3.20	95	3.20	95	3.21
N_2	25730	69.24	2058	69.22	2058	69.64
SO_2	178	0.48	14	0.47	14	0.47
SO_3	2.01	0.01	0.16	0.01	0.16	0.01
NO	14.28	0.04	1.14	0.04	1.14	0.04
NO_2	1.15	0.0003	0.09	0.0003	0.09	0.0003
HCl	4.75	0.01	0.38	0.01	0.38	0.01
H_2O	2173	5.85	174	5.85	174	5.89
Ash	225	0.61	18	0.61	0.11	0.004
Total	37161	100	2973	100	2955	100

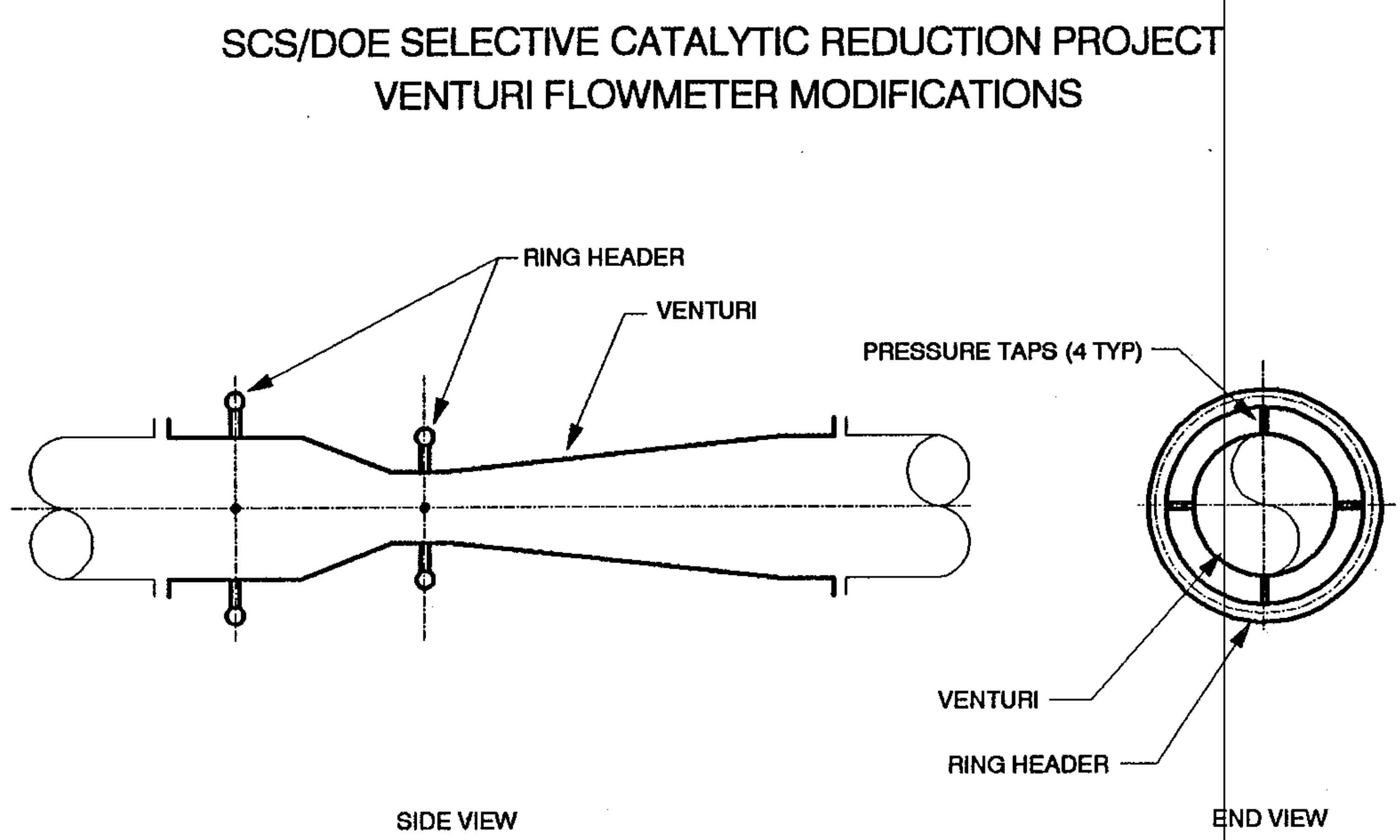


Figure 4.1-7. Sketch of the Venturi.

with round to rectangular duct transition; b) addition of a diffuser, equipped with internal baffle plates and expansion in only one dimension; and c) transition from horizontal to vertical flow into the reactor inlet is equipped with turning vanes.

The model design achieving the best velocity uniformity results and requiring the minimum space is shown in Figure 4.1-8, along with the testing arrangements in Figure 4.1-9. The velocity profile data for the inlet geometry in the round piping ductwork is shown in Figure 4.1-10 to be uniform and symmetric. However, in initial flow model testing, the velocity profile uniformity at location 2, which is the diffuser outlet, was much less uniform than at location 1 with high velocities, about 50 percent above average, in the center, and low velocities at the walls, as shown in Figure 4.1-11. This phenomena resulted from the flow area expansion from a 1 foot circle to a 1 foot square, followed by the expansion across the diffuser to a 1.5 foot x 2 foot cross-section. To reduce the velocities and distribute the flow more uniformly, a set of resistance pipes was located immediately at the outlet of the circle to square transition (which also corresponds to a possible ammonia injection cross-section).

Slight modifications in detail geometry of the resistance pipes progressively improved location 2, the diffuser outlet, uniformity from 16.7 percent of data within +/- 10 percent, as depicted in Figure 4.1-11, to 87.5 percent of data within +/- 10 percent for the final resistance pipe design selected and shown in Figure 4.1-12.

The velocity profile test results for the optimum design tested are summarized in Table 4.1-3, with graphical display of results at locations 3 (core inlet) and 4 (core outlet) presented in Figures 4.1-13 and 4.1-14.

About 96 percent of the results were within +\- 10 percent of the average velocity and 99 percent of the results were within ± 15 percent of the average.

MODEL GEOMETRY FOR ELBOW VANES AND DIFFUSER BAFFLES
FOR REACTOR INLET MODEL DESIGN NO. 1
(Model Scale Factor = 2)

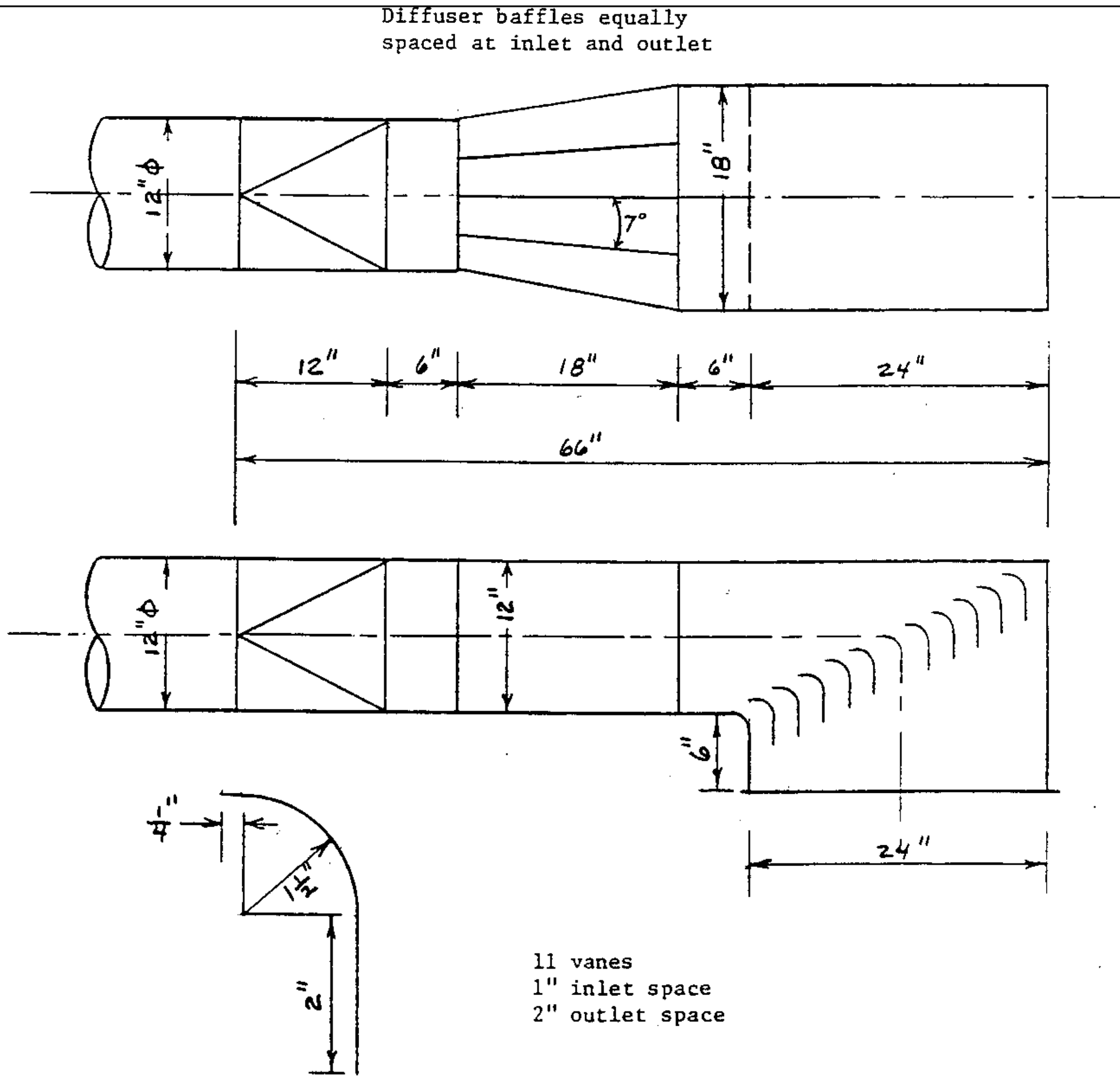


Figure 4.1-8. **Reactor inlet model design achieving best velocity uniformity results.**

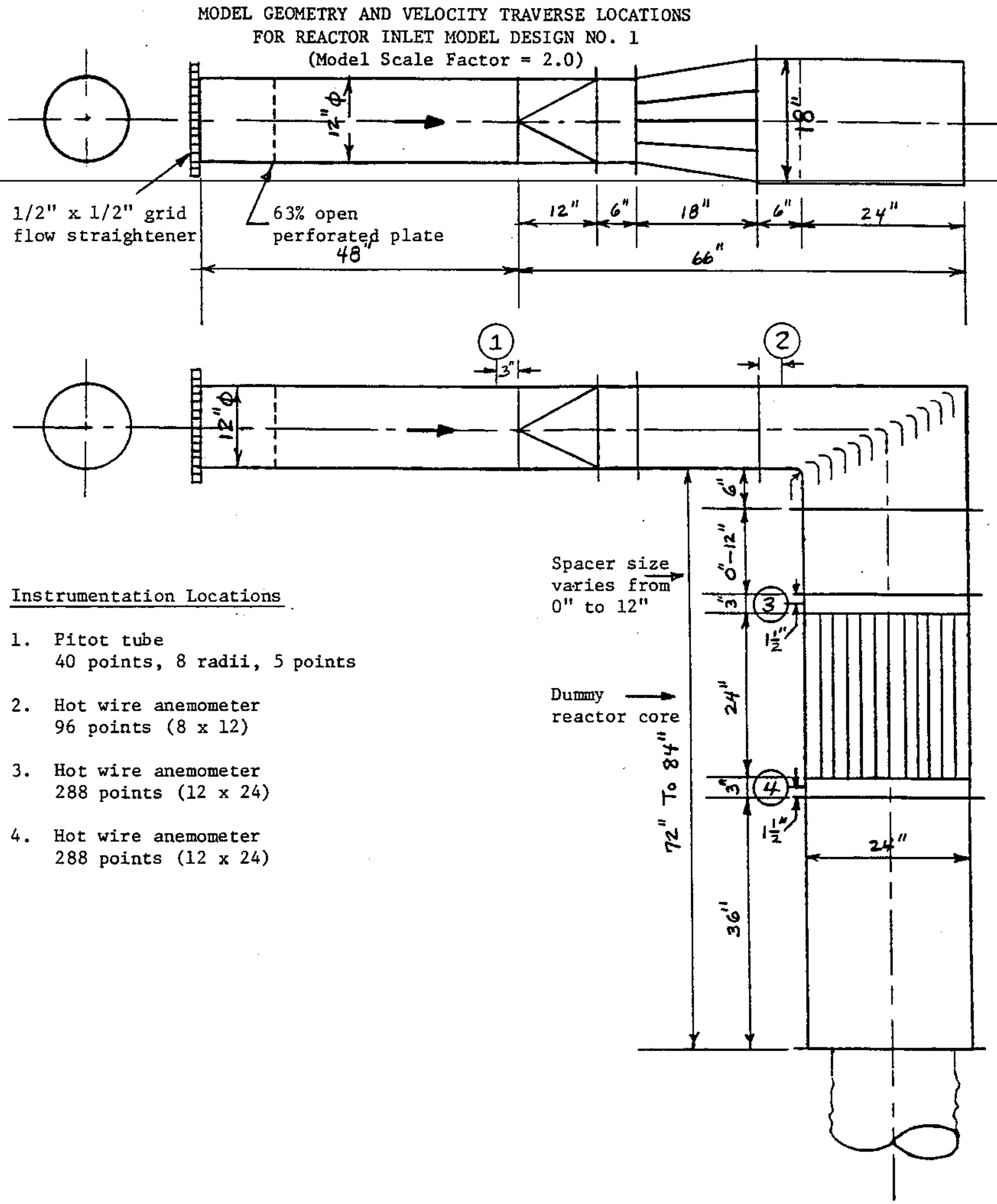
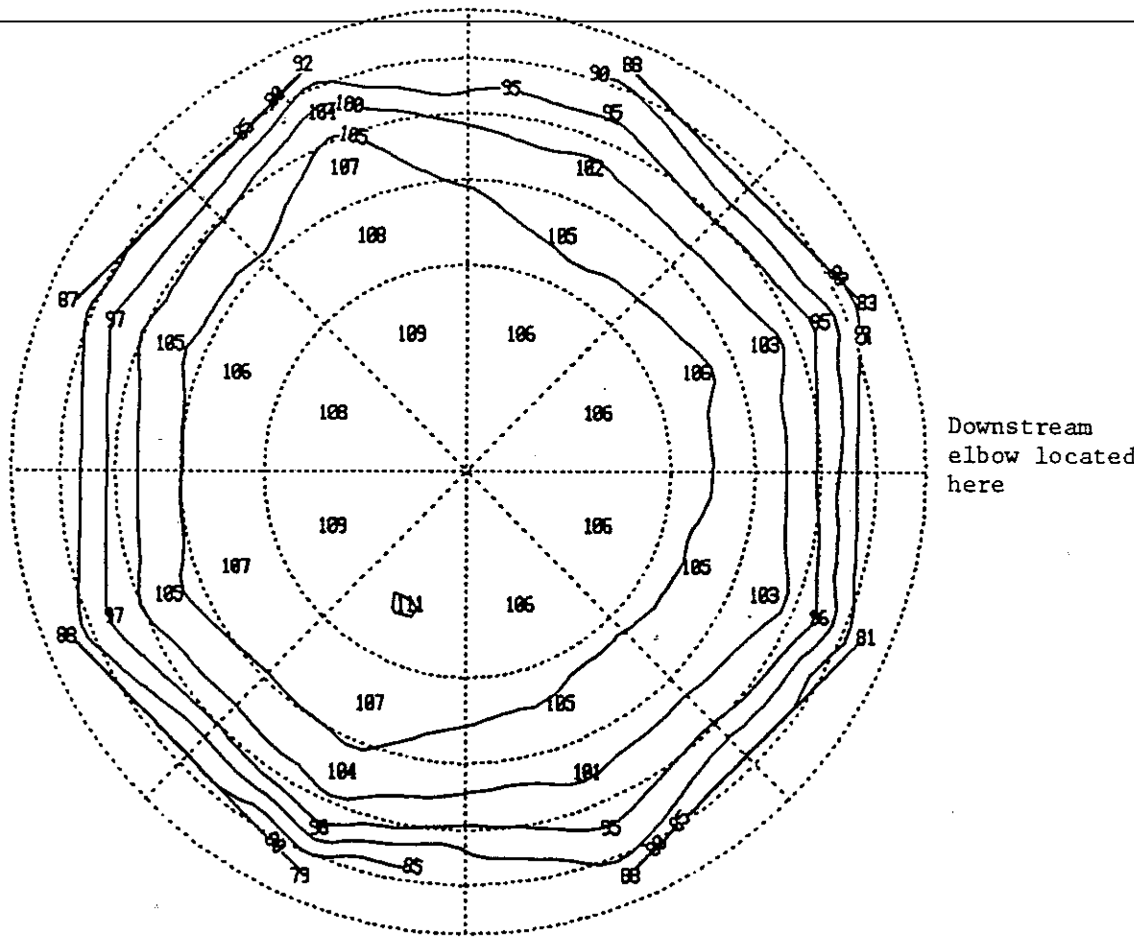


Figure 4.1-9. Reactor inlet model design testing arrangements.

MODEL INLET PIPE VELOCITY PROFILE AT LOCATION 1
FOR GEOMETRY DOCUMENTED ON FIGURE 1
APPLICABLE TO ALL TESTS FOR REACTOR INLET DESIGN NO. 1

Percent of average velocity
Flow out of paper



Data located at center of equal area segments

RMS = 0.084

% of data within bands

±10%	80%
±15%	92.5%
±25%	100%

Figure 4.1-10. Velocity profile data for round piping ductwork in reactor inlet model.

FIGURE 6 TEST No. 10x11 ISO-VELOCITY CONTOURS
BASE CONFIGURATION REACTOR INLET DESIGN #1
SPACER BETWEEN ELBOW AND CORE NO
RESISTANCE PIPE NEAR DIFFUSER INLET NO
TRAVERSE LOCATION DOWN STREAM OF DIFFUSER 2

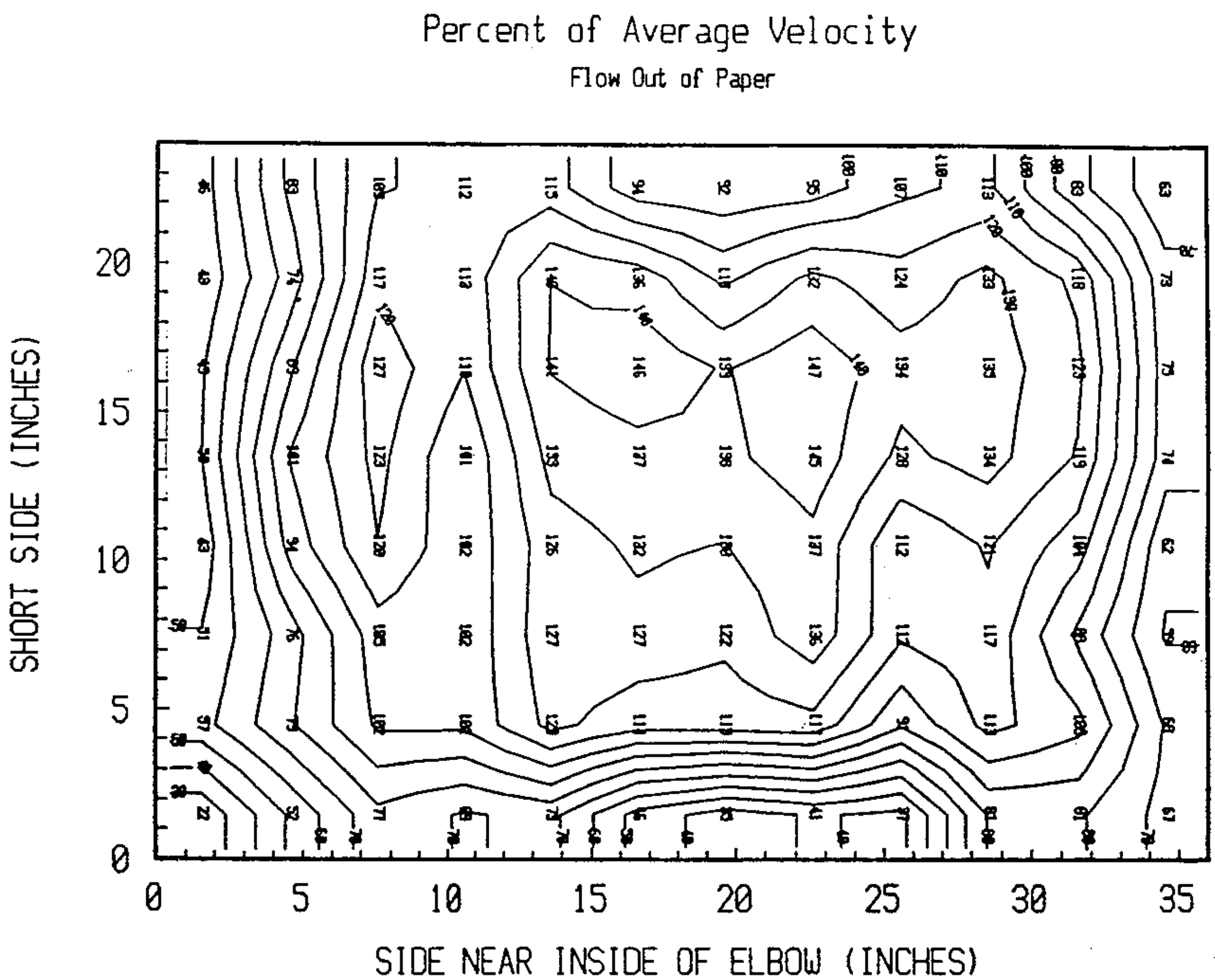


Figure 4.1-11. Initial velocity profile data at location 2, diffuser outlet, with poor uniformity results.

Table 4.1-3

Velocity Profile Test Results Summary for Selected Model Reactor Inlet Design

Geometry Description	Location No. Description	RMS[a]	± 10%(%)[b]	± 15%(%)[c]
Open design with elbow and diffuser vanes/	2 - Diffuser Outlet	0.066	87.5	97.9
	3 - Dummy	0.074	86.1	95.5
No space between elbow and core/	Layer Inlet			
	4 - Dummy	0.049	95.5	99.0
Fine 1" dowels unequally spaced, 58.3% open average	Layer Outlet			

a) RMS = Standard deviation of velocity about an average velocity, expressed as a fraction of the average velocity. For a value of zero, the flow would be perfectly uniform with all data points equal.

b) Percentage of data within ± 10% band about the average.

c) Percentage of data within ± 15% band about the average.

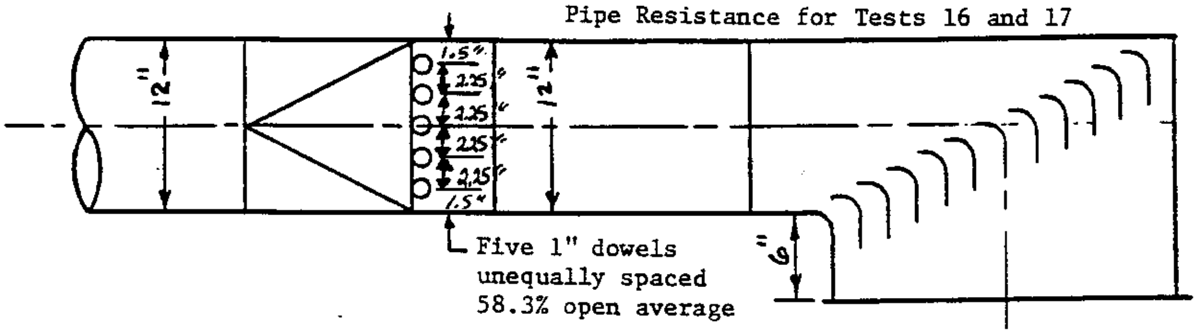


Figure 4.1-12. Detailed geometry of the resistance pipes. (USAD as ammonia injection grade.)

TEST No. 17 ISO-VELOCITY CONTOURS
BASE CONFIGURATION REACTOR INLET DESIGN #1
SPACER BETWEEN ELBOW CORE NO
RESISTANCE PIPES NEAR DIFFUSER INLET YES
TRAVERSE LOCATION 3 CORE INLET

Percent Of Average Velocity
Flow Out of Paper

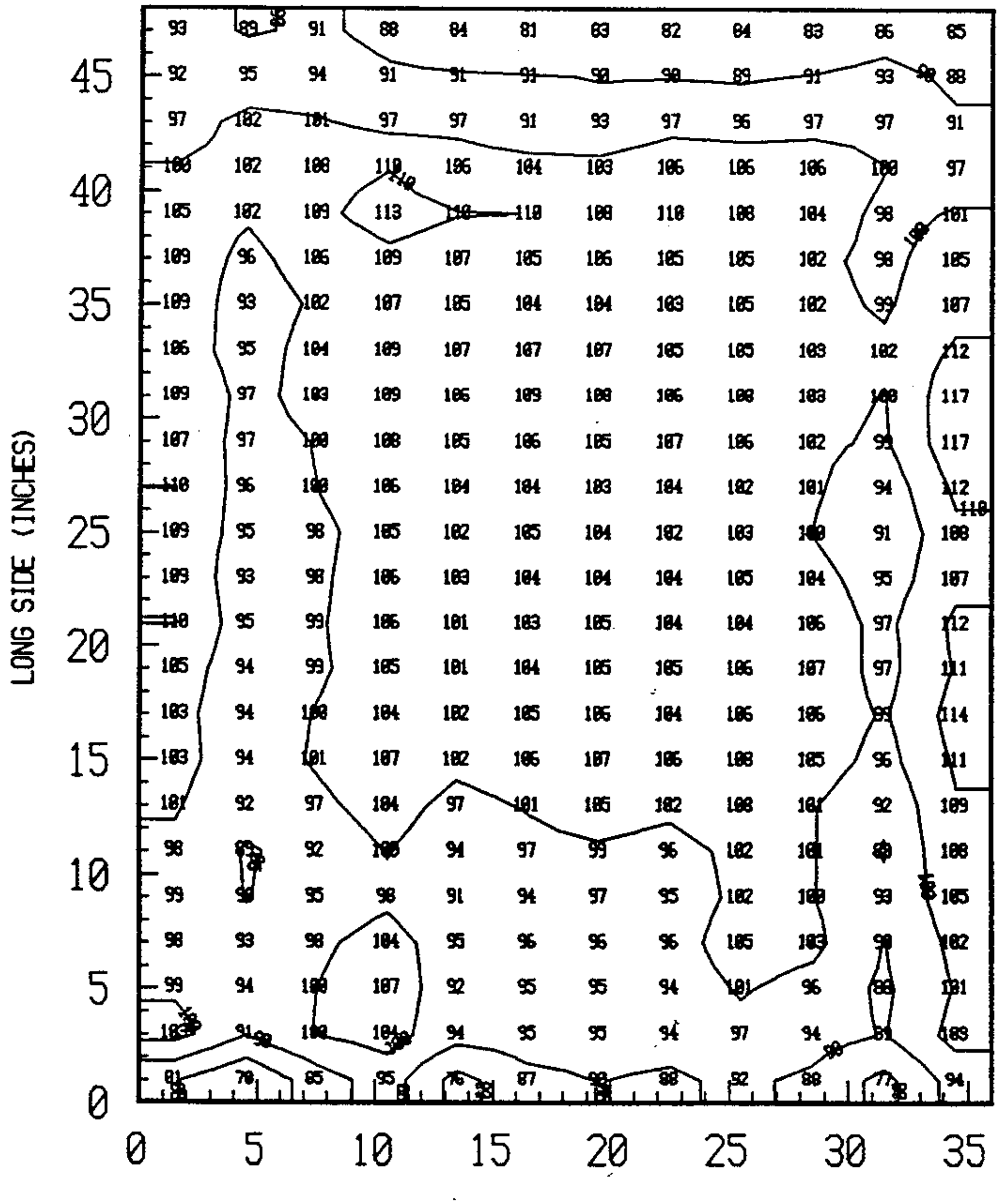


Figure 4.1-13. Graphical display of test results at location 3.

TEST No. 17 ISO-VELOCITY CONTOURS
BASE CONFIGURATION REACTOR INLET DESIGN #1
SPACER BETWEEN ELBOW CORE NO
RESISTANCE PIPES NEAR DIFFUSER INLET YES
TRAVERSE LOCATION 4 CORE OUTLET

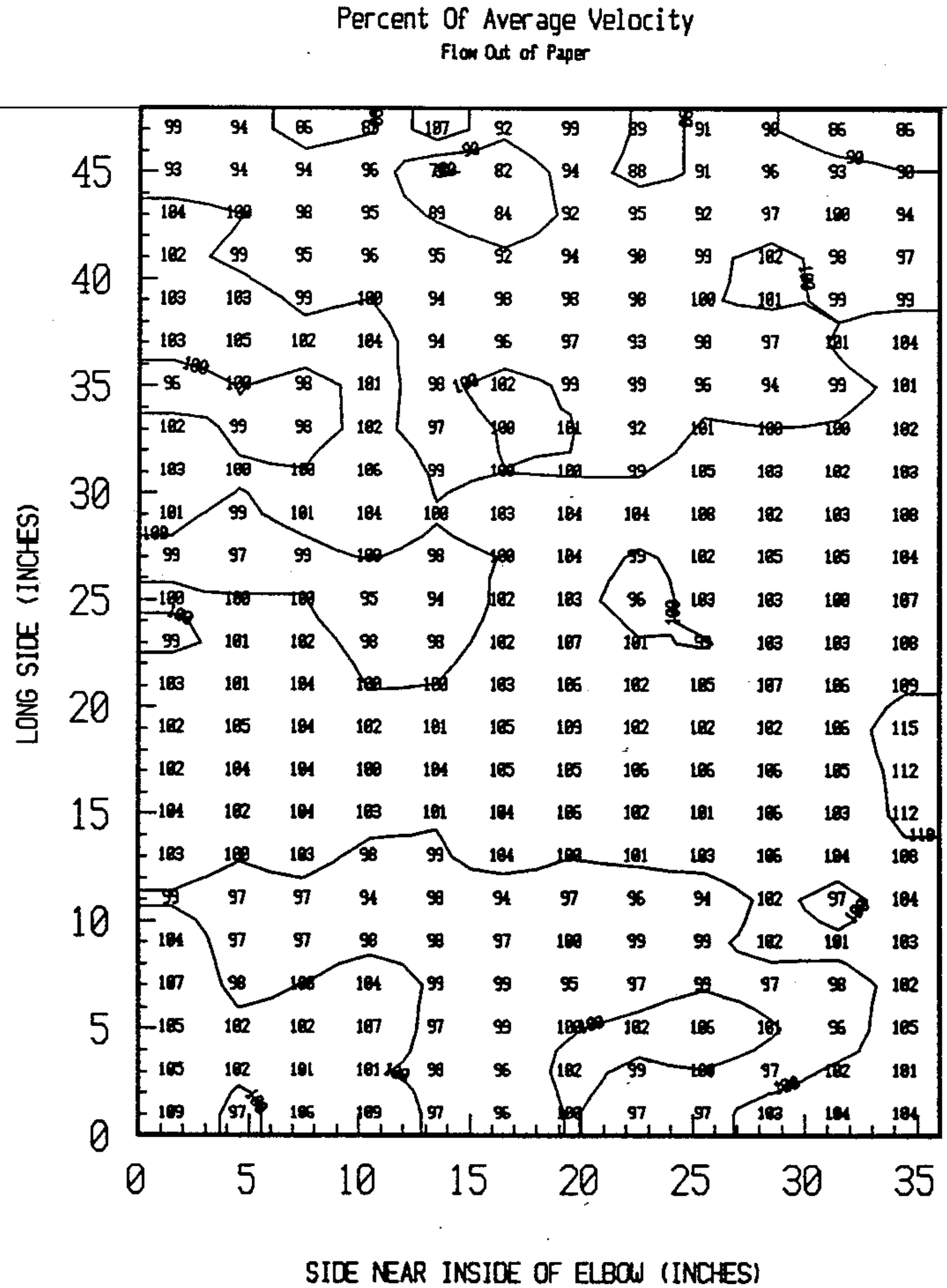


Figure 4.1-14. Graphical display of test results at location 4.

Conclusions from the above DynaGen flow modeling results are as follows:

1. This is the minimum height and length design and is a more practical field unit configuration.

2. The initial base design, with elbow vanes and diffuser baffles but no resistance pipes, was very poor.

3. Resistance pipes are needed at the outlet of the circle to square transition to improve velocity profile uniformity.

4. The best velocity uniformity results achieved for test 17 were RMS + 0.049, 95.5 percent of data with +/- 10 percent of average, and 99.0 percent of data within +/- 15 percent.

5. This velocity uniformity could be improved further by:

    a. adding more dummy core length;
    b. using unequally spaced vanes; or
    c. adding a second resistance at the diffuser outlet or the elbow outlet.

6. The pressure loss is low from Location 1 in the inlet pipe to Location 4 at the core outlet and is about 0.69 in. of water at field operating conditions.

7. The pipe resistance can be used as the grid for the ammonia injection nozzles.

8. The use of a 12 in. model spacer between the elbow outlet and dummy core inlet gives better results above the dummy core but worse results at the dummy core outlet.

In follow-up testing to evaluate vertical versus the previously-tested horizontal arrangements for resistance pipes, it was concluded that the horizontal arrangement provided the best velocity uniformity results and so the final design will incorporate the horizontal resistance pipe configuration. One change, from figures previously shown, increases from a four-cell diffuser with three baffles, to a five cell diffuser with four baffles. This will better match with a 5 x 5 nozzle array for ammonia injection (See Section 5.0, Area 300.)

EXHIBIT 4.1-A

DYNAGEN'S SYSTEM LAYOUT GUIDELINES AND SUGGESTIONS

DISCUSSION OF BASIC DESIGN FOR THE SCR PILOT PLANT SYSTEM BEING DESIGNED FOR THE CRIST STEAM PLANT

DynaGen, Inc. Project No. SCS-2
DynaGen, Inc. Report No. 2486
SCS Contract No. 195-89-044
DOE Clean Coal Program

Submitted to:

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, Alabama 35202

Prepared by:

Gerald B. Gilbert

September 18, 1990

Submitted by:

DynaGen, Inc.
99 Erie Street
Cambridge, Massachusetts 02139

Telephone (617) 491-2527

Section 8

SYSTEM LAYOUT GUIDELINES AND SUGGESTIONS

8.1 Desireable Piping Components

The use of round pipe, elbows, and junctions will be satisfactory for the SCR system. Some suggested components are shown on Figures 4, 5, and 6 with the following comments:

1. When elbows are used, they should be standard, long radius, smooth elbows or equivalent mitered elbows with about 4 miters.

2. Figure 4 shows geometry and pressure loss for 45° diverging Wye junctions that could be used for the takeoffs to the large reactors. The main duct area should be reduced to maintain a constant design velocity level. The take off to the last reactor should be a standard, long radius elbow. The take off should be to the side rather than down so that the dust loading is not biased by pulling flow off the bottom of the duct. The use of a wye junction will reduce pressure loss, improve take off pipe velocity profile, and produce a more stable flow pattern free of flow separations.

3. Figure 5 shows geometry and pressure loss for small take off pipes at 45° to a constant area main pipe that could be used for the small reactor take offs from the main supply pipe. In addition to these, the take off pipe could continue at an angle or turn upward parallel to the main supply pipe. My recommendation is that these small take offs be located in the vertical run of the main supply pipe. They do not all need to be off the same side of the main supply pipe. Above the last small takeoff, reduce the main supply pipe area to increase the velocity back to the design value.

4. Figure 6 shows geometry and pressure loss for several converging flow Wye junctions that could be used downstream of the fan. The Wye junctions will have lower pressure loss and more stable flow patterns.

5. A design velocity level of 60 fps should be satisfactory to prevent significant dust stratification but I will evaluate this further when I receive the particle size results from the Unit 5 field test.

8.2 Venturi Meter Installation Requirements

I have enclosed pages from the ASME power test code PTC 19.5; 4-1959 on flow measurement. This is the 1959 edition. I am trying to find out if there is a more recent version and will send you a copy when I get hold of it. Here are some comments:

1. Use a venturi of standard dimensions for which ASME discharge coefficients apply unless you want to calibrate a non-standard venturi. A venturi supplier should also be able to provide a calibration.

2. Calculate your Reynolds numbers to see where you are for discharge coefficient on Figure 15. You are probably above 200,000.

3. Use a flow straightener to eliminate any swirl at the venturi meter inlet.

4. Use Figure 16 to determine the length of straight pipe needed upstream of the venturi.

5. You could also use an ASME nozzle flow meter but the added pipe requirements up and downstream may not make it any shorter. Also, the pressure loss will be greater and the downstream flow will be more distorted and turbulent.

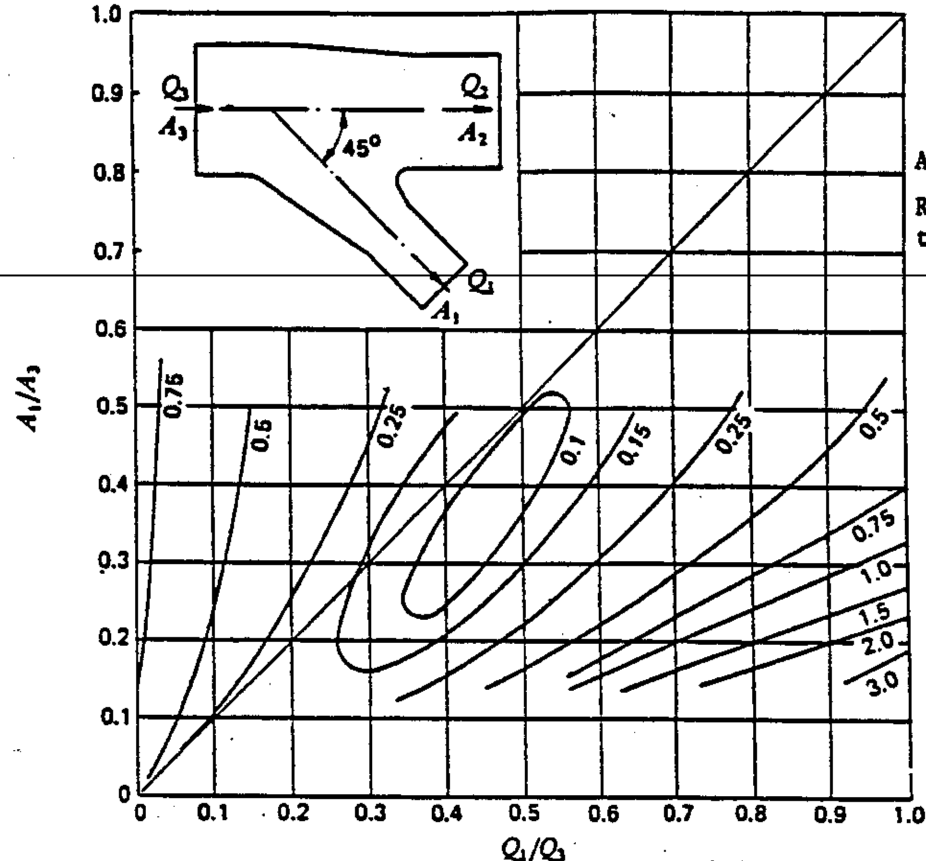
6. Read the installation instructions carefully.

7. Since your flow meter will be at high temperature, there will be corrections for thermal expansion.

8. Also attached are the flow rate calculation procedures and equation factors needed for gas flow.

Figure 4

CIRCULAR DIVERGING FLOW JUNCTIONS FOR MANIFOLD TO LARGE REACTORS



$A_2 = A_3 - A_1$
Round or Close to Square

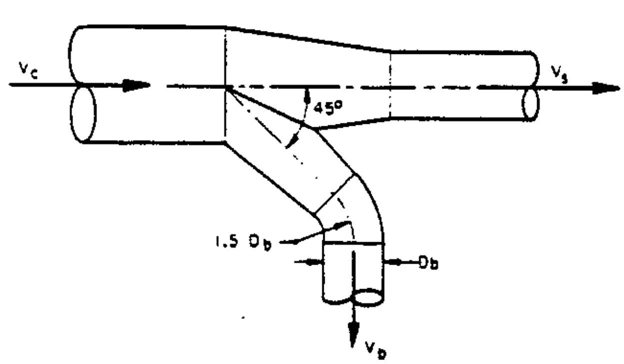
A-47

Fig. 13.26. Improved performance 45° dividing junction, $A_2 = A_3 - A_1$, loss coefficient K_{31}

MILLER 1978

5-17 Wye, 45°, Diverging, Conical Main and Branch, with 45° Elbow, Branch 90° to Main (Idelchik 1986, Diagram 7-19)

ASHRAE 1986



Branch

V_b/V_c	0.2	0.4	0.6	0.7	0.8	0.9	1.0	1.1	1.2
$C_{c,b}$	0.76	0.60	0.52	0.50	0.51	0.52	0.56	0.61	0.68
V_b/V_c	1.4	1.6	1.8	2.0	2.2	2.4	2.6	2.8	3.0
$C_{c,b}$	0.86	1.1	1.4	1.8	2.2	2.6	3.1	3.7	4.2

Main

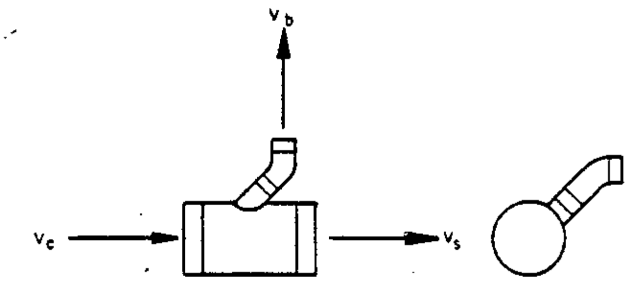
V_s/V_c	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
$C_{c,s}$	0.14	0.06	0.05	0.09	0.18	0.30	0.46	0.64	0.84	1.0

Figure 5

CIRCULAR DIVERGING FLOW JUNCTIONS FOR SMALL TAKE OFFS TO SMALL REACTORS

Duct Design ASHRAE 1986

5-15 Wye, 45°, Round, with 60° Elbow, Branch 90° to Main (Jones 1969, Fig. 3)

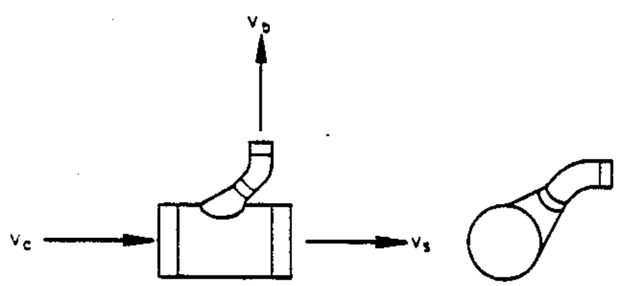


$A_c = A_s$

Branch											
V_b/V_c	0	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
$C_{c,b}$	1.0	0.88	0.77	0.68	0.65	0.69	0.73	0.88	1.14	1.54	2.2

For main loss coefficient ($C_{c,s}$), see Fitting 5-23.

5-16 Wye, 45°, Diverging, Round (Conical Branch), with 60° Elbow, Branch 90° to Main (Jones 1969, Fig. 20)



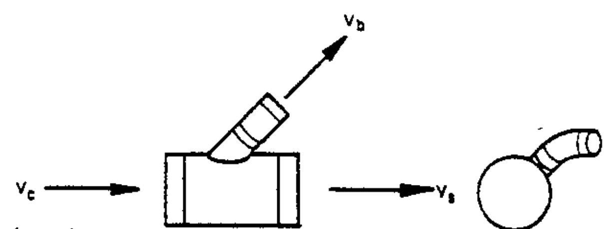
For wye geometry, see Fitting 5-11.

$A_c = A_s$

Branch											
V_b/V_c	0	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
$C_{c,b}$	1.0	0.82	0.63	0.52	0.45	0.42	0.41	0.40	0.41	0.45	0.56

For main loss coefficient ($C_{c,s}$), see Fitting 5-23.

5-20 Wye, 45°, Diverging, Round, with 30° Elbow, Branch 45° to Main (Jones 1969, Fig. 2)

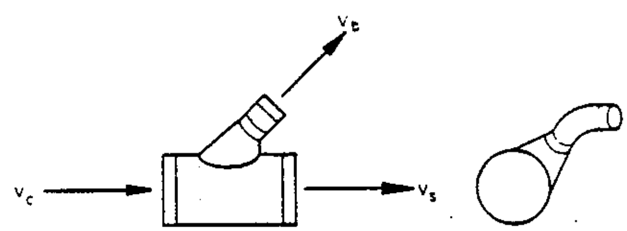


$A_c = A_s$

Branch											
V_b/V_c	0	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
$C_{c,b}$	1.0	0.84	0.72	0.62	0.54	0.50	0.56	0.71	0.92	1.22	1.66

For main loss coefficient ($C_{c,s}$), see Fitting 5-23.

5-21 Wye, 45°, Diverging, Round (Conical Branch), with 30° Elbow, Branch 45° to Main (Jones 1969, Fig. 24)



For wye geometry, see Fitting 5-11.

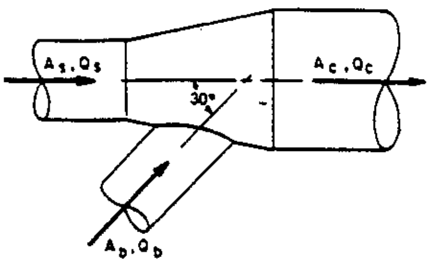
$A_c = A_s$

Branch											
V_b/V_c	0	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
$C_{c,b}$	1.0	0.93	0.71	0.55	0.44	0.42	0.42	0.44	0.47	0.54	0.62

For main loss coefficient ($C_{c,s}$), see Fitting 5-23.

Wye, 30° Converging, Round, Conical Main (Sepsy 1973)

ASHRAE 1986



Branch, $C_{c,b}$

A_s/A_c	A_b/A_c	Q_b/Q_s 0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
0.3	0.2	−2.4	−.11	1.8	3.4	4.8	6.0	7.1	8.0	8.9	9.7
	0.3	−2.8	−1.3	0.14	0.72	1.4	2.0	2.4	2.8	3.2	3.5
0.4	0.2	−1.4	0.61	2.3	3.8	5.2	6.3	7.3	8.3	9.1	9.8
	0.3	−1.8	−.54	0.42	1.2	1.8	2.3	2.7	3.1	3.4	3.7
	0.4	−1.9	−.89	−.17	0.36	0.76	1.1	1.3	1.5	1.7	1.9
0.5	0.2	−.82	0.97	2.6	4.0	5.3	6.4	7.4	8.3	9.1	9.9
	0.3	−1.2	−.15	0.71	1.4	2.0	2.5	2.9	3.3	3.6	3.9
	0.4	−1.4	−.54	0.06	0.50	0.85	1.1	1.3	1.5	1.7	1.8
	0.5	−1.4	−.66	−.15	0.21	0.48	0.68	0.84	0.97	1.1	1.2
0.6	0.2	−.52	1.2	2.7	4.1	5.3	6.4	7.4	8.3	9.1	9.9
	0.3	−.93	0.06	0.85	1.5	2.1	2.6	3.0	3.4	3.7	4.0
	0.4	−1.1	−.37	0.16	0.55	0.86	1.1	1.3	1.4	1.6	1.8
	0.5	−1.1	−.49	−.06	0.25	0.48	0.66	0.79	0.90	1.0	1.1
	0.6	−1.2	−.55	−.15	0.12	0.31	0.45	0.56	0.65	0.71	0.77
0.8	0.2	−.27	1.3	2.7	4.0	5.2	6.3	7.3	8.2	9.0	9.7
	0.3	−.67	0.18	0.90	1.5	2.0	2.5	2.9	3.3	3.6	4.0
	0.4	−.85	−.27	0.16	0.49	0.75	0.97	1.2	1.3	1.4	1.6
	0.5	−.90	−.40	−.07	0.18	0.36	0.50	0.61	0.70	0.78	0.84
	0.6	−.92	−.46	−.16	0.04	0.18	0.29	0.37	0.44	0.49	0.53
	0.7	−.93	−.49	−.21	−.03	0.10	0.19	0.25	0.30	0.34	0.37
	0.8	−.93	−.50	−.24	−.07	0.05	0.13	0.19	0.23	0.27	0.29
1.0	0.2	−.26	1.2	2.6	3.9	5.1	6.1	7.1	8.0	8.8	9.5
	0.3	−.65	0.12	0.79	1.4	1.9	2.4	2.8	3.1	3.5	3.8
	0.4	−.83	−.34	0.04	0.33	0.58	0.78	0.95	1.1	1.2	1.3
	0.5	−.89	−.48	−.20	0	0.15	0.27	0.37	0.45	0.51	0.57
	0.6	−.91	−.54	−.31	−.14	−.03	0.06	0.12	0.18	0.22	0.25
	0.8	−.93	−.59	−.38	−.25	−.16	−.10	−.06	−.03	−.01	0.01
	1.0	−.93	−.60	−.40	−.28	−.20	−.14	−.11	−.08	−.07	−.06

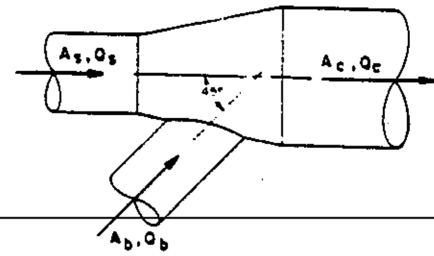
Main, $C_{c,s}$

A_s/A_c	A_b/A_c	Q_b/Q_s 0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	0.8	2.0
0.3	0.2	4.5	2.8	1.5	0.56	−.17	−.74	−1.2	−1.6	−1.9	−2.1
	0.3	4.6	3.1	2.0	1.2	0.57	0.08	−.30	−.62	−.89	−1.1
0.4	0.2	1.6	0.85	0.16	−.43	−.92	−1.3	−1.7	−1.9	−2.2	−2.4
	0.3	1.7	1.1	0.58	0.13	−.24	−.56	−.82	−1.1	−1.3	−1.4
	0.4	1.8	1.3	0.80	0.42	0.11	−.15	−.37	−.55	−.72	−.86
0.5	0.2	0.67	0.18	−.33	−.79	−1.2	−1.5	−1.8	−2.1	−2.3	−2.5
	0.3	0.75	0.42	0.07	−.25	−.54	−.80	−1.0	−1.2	−1.4	−1.5
	0.3	0.80	0.55	0.28	0.03	−.20	−.40	−.57	−.73	−.86	−.98
	0.5	0.82	0.62	0.41	0.20	0.02	−.15	−.29	−.42	−.53	−.63
0.6	0.2	0.26	−.11	−.54	−.95	−1.3	−1.6	−1.9	−2.1	−2.4	−2.5
	0.3	0.34	0.13	−.14	−.42	−.67	−.90	−1.1	−1.3	−1.4	−1.6
	0.4	0.39	0.25	0.06	−.14	−.33	−.51	−.66	−.80	−.93	[illegible]
	0.5	0.41	0.32	0.18	0.03	−.12	−.26	−.38	−.50	−.6	−.66
	0.6	0.43	0.37	0.26	0.14	0.02	−.09	−.19	−.28	−.37	−.45
0.8	0.2	−.01	−.30	−.67	−1.1	−1.4	−1.7	−2.0	−2.2	−2.4	−2.6
	0.3	0.07	−.07	−.29	−.56	−.76	−.97	−1.2	−1.3	−1.5	−1.6
	0.4	0.11	0.05	−.09	−.26	−.42	−.58	−.72	−.85	−.97	−1.1
	0.5	0.14	0.12	0.03	−.09	−.21	−.34	−.45	−.55	−.64	−.73
	0.6	0.15	0.17	0.11	0.02	−.07	−.17	−.26	−.34	−.42	−.49
	0.7	0.17	0.21	0.17	0.11	0.03	−.05	−.12	−.19	−.26	−.32
	0.8	0.17	0.23	0.22	0.17	0.11	0.05	−.02	−.07	−.13	−.18
1.0	0.2	−.05	−.33	−.70	−1.1	−1.4	−1.7	−2.0	−2.2	−2.4	−2.6
	0.3	0.03	−.10	−.31	−.55	−.76	−.98	−1.2	−1.3	−1.5	−1.6
	0.4	0.07	0.02	−.12	−.28	−.44	−.59	−.73	−.86	−.98	−1.1
	0.5	0.09	0.09	0.01	−.11	−.23	−.35	−.46	−.56	−.65	−.74
	0.6	0.11	0.14	0.09	0	−.09	−.18	−.27	−.35	−.43	−.50
	0.8	0.13	0.20	0.19	0.15	0.09	0.03	−.03	−.08	−.14	−.19
	1.0	0.14	0.24	0.25	0.24	0.20	0.16	0.12	0.08	0.04	0

Figure 6

CIRCULAR CONVERGING FLOW JUNCTIONS FOR MANIFOLD DOWNSTREAM OF FANS

5-5 Wye, 45° Converging, Round, Conical Main (Sepsy 1973)



Branch, $C_{c,b}$

A_s/A_c	A_b/A_c	Q_b/Q_s 0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
0.3	0.2	−2.4	−01	2.0	3.8	5.3	6.6	7.8	8.9	9.8	11
	0.3	−2.8	−1.2	0.12	1.1	1.9	2.6	3.2	3.7	4.2	4.6
0.4	0.2	−1.2	0.93	2.8	4.5	5.9	7.2	8.4	9.5	10	11
	0.3	−1.6	−.27	0.81	1.7	2.4	3.0	3.6	4.1	4.5	4.9
	0.4	−1.8	−.72	0.07	0.66	1.1	1.5	1.8	2.1	2.3	2.5
0.5	0.2	−.46	1.5	3.3	4.9	6.4	7.7	8.8	9.9	11	12
	0.3	−.94	0.25	1.2	2.0	2.7	3.3	3.8	4.2	4.7	5.0
	0.4	−1.1	−.24	0.42	0.92	1.3	1.6	1.9	2.1	2.3	2.5
	0.5	−1.2	−.38	0.18	0.58	0.88	1.1	1.3	1.5	1.6	1.7
0.6	0.2	−.55	1.3	3.1	4.7	6.1	7.4	8.6	9.6	11	12
	0.3	−1.1	0	0.88	1.6	2.3	2.8	3.3	3.7	4.1	4.5
	0.4	−1.2	−.48	0.10	0.54	0.89	1.2	1.4	1.6	1.8	2.0
	0.5	−1.3	−.62	−.14	0.21	0.47	0.68	0.85	0.99	1.1	1.2
	0.6	−1.3	−.69	−.26	0.04	0.26	0.42	0.57	0.66	0.75	0.82
0.8	0.2	0.06	1.8	3.5	5.1	6.5	7.8	8.9	10	11	12
	0.3	−.52	0.35	1.1	1.7	2.3	2.8	3.2	3.6	3.9	4.2
	0.4	−.67	−.05	0.43	0.80	1.1	1.4	1.6	1.8	1.9	2.1
	0.6	−.75	−.27	0.05	0.28	0.45	0.58	0.68	0.76	0.83	0.88
	0.7	−.77	−.31	−.02	0.16	0.32	0.43	0.50	0.56	0.61	0.65
	0.8	−.78	−.34	−.07	0.12	0.24	0.33	0.39	0.44	0.47	0.50
1.0	0.2	0.40	2.1	3.7	5.2	6.6	7.8	9.0	11	11	12
	0.3	−.21	0.54	1.2	1.8	2.3	2.7	3.1	3.7	3.7	4.0
	0.4	−.33	0.21	0.62	0.96	1.2	1.5	1.7	2.0	2.0	2.1
	0.5	−.38	0.05	0.37	0.60	0.79	0.93	1.1	1.2	1.2	1.3
	0.6	−.41	−.02	0.23	0.42	0.55	0.66	0.73	0.80	0.85	0.89
	0.8	−.44	−.10	0.11	0.24	0.33	0.39	0.43	0.46	0.47	0.48
	1.0	−.46	−.14	0.05	0.16	0.23	0.27	0.29	0.30	0.30	0.29

Main, $C_{c,s}$

A_s/A_c	A_b/A_c	Q_b/Q_s 0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0
0.3	0.2	5.3	−.01	2.0	1.1	0.34	−.20	−.61	−.93	−1.2	−1.4
	0.3	5.4	3.7	2.5	1.6	1.0	0.53	0.16	−.14	−.38	−.58
0.4	0.2	1.9	1.1	0.46	−.07	−.49	−.83	−1.1	−1.3	−1.5	−1.7
	0.3	2.0	1.4	0.81	0.42	0.05	−.20	−.43	−.62	−.78	−.92
	0.4	2.0	1.5	1.0	0.68	0.39	0.16	−.04	−.21	−.35	−.47
0.5	0.2	0.77	0.34	−.09	−.45	−.81	−1.1	−1.3	−1.5	−1.7	−1.8
	0.3	0.85	0.56	0.25	−.03	−.27	−.48	−.67	−.82	−.96	−1.1
	0.4	0.85	0.66	0.43	0.21	0.02	−.15	−.30	−.42	−.54	−.64
	0.5	0.91	0.73	0.54	0.36	0.21	0.06	−.06	−.17	−.26	−.35
0.6	0.2	0.30	0	−.34	−.67	−.96	−1.2	−1.4	−1.6	−1.8	−1.9
	0.3	0.37	0.21	−.02	−.24	−.44	−.63	−.79	−.93	−1.1	−1.2
	0.4	0.40	0.31	0.16	−.01	−.16	−.30	−.43	−.54	−.64	−.73
	0.5	0.43	0.37	0.26	0.14	0.02	−.09	−.20	−.29	−.37	−.45
	0.6	0.44	0.41	0.33	0.24	0.14	0.05	−.03	−.11	−.18	−.25
0.8	0.2	−.06	−.27	−.57	−.86	−1.1	−1.4	−1.6	−1.7	−1.9	−2.0
	0.3	0	−.08	−.25	−.43	−.62	−.78	−.93	−1.1	−1.2	−1.3
	0.4	0.04	0.02	−.08	−.21	−.34	−.46	−.57	−.67	−.77	−.85
	0.5	0.06	0.08	0.02	−.06	−.16	−.25	−.34	−.42	−.50	−.57
	0.6	0.07	0.12	0.09	0.03	−.04	−.11	−.18	−.25	−.31	−.37
	0.7	0.08	0.15	0.14	0.10	0.05	−.01	−.07	−.12	−.17	−.22
	0.8	0.09	0.17	0.18	0.16	0.11	0.07	0.02	−.02	−.07	−.11
1.0	0.2	−.19	−.39	−.67	−.96	−1.2	−1.5	−1.6	−1.8	−2.0	−2.1
	0.3	−.12	−.19	−.35	−.54	−.71	−.87	−1.0	−1.2	−1.3	−1.4
	0.4	−.09	−.10	−.19	−.31	−.43	−.55	−.66	−.77	−.86	−.94
	0.5	−.07	−.04	−.09	−.17	−.26	−.35	−.44	−.52	−.59	−.66
	0.6	−.06	0	−.02	−.07	−.14	−.21	−.28	−.34	−.40	−.46
	0.8	−.04	0.06	0.07	0.05	0.02	−.03	−.07	−.12	−.16	−.2
	1.0	−0.3	0.09	0.13	0.13	0.11	0.08	0.06	0.03	−.01	−.03

EXHIBIT 4.1-B

FLOW MEASUREMENT EXERPT FROM DYNAGEN

72

PTC 19.5;4-1959

CHAPTER 4

Flow Measurement

Part 5—Measurement of Quantity of Materials

INSTRUMENTS AND APPARATUS

POWER TEST CODES

THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
United Engineering Center
345 East 47th Street New York, N.Y. 10017

(*b*) If the nozzle using pipe taps has not been individually calibrated, the coefficient of discharge shall be obtained from Figs. 10 and 11 for all sizes of pipe. Note that these curves do not include the velocity of approach factor $F = \frac{1}{\sqrt{1-\beta^4}}$. Interpolate linearly between curves of the nearest Reynolds numbers on Fig. 11 to determine the coefficient of discharge for any intermediate value of Reynolds number. In Fig. 10, interpolate linearly for any intermediate value of β.

(*c*) If throat taps are used with the flow nozzle or if special forms of flow nozzles are used, the coefficient of discharge shall be determined by actual calibration, as covered in Par. 18. The coefficients for pipe wall tap nozzles cannot be applied to throat tap nozzles.

(*d*) Unless nozzles used at either the inlet or outlet of a plenum chamber have been individually calibrated, the value of the coefficient of discharge shall be taken as 0.99 provided that the throat Reynolds number exceeds 200,000.

30 Pressure Loss. The pressure loss produced by a flow nozzle may be estimated from the curves in Fig. 5.

C, Venturi Tubes

31 Kind and Construction.

(*a*) *Standard Form (Herschel Type)*

(*1*) Dimensions for standard forms are shown in Fig. 12. The inlet section shall consist of a short cylindrical section joined by a smooth curve to a truncated cone having an included angle of 21 deg ± 2 deg. The inlet cone shall be joined by another smooth curve to a short cylindrical section called the throat. The exit from this throat section shall lead by another easy curve to the exit or diffuser cone which shall have an included angle between 5 and 15 deg.

(*2*) If the inlet and throat consist of more than one section, there shall be no step or protruding gasket at the joint.

(*3*) Each of the inlet and throat sections must contain a piezometer ring or annular chamber for measuring the static pressure at these points. The fluid enters this chamber through equally spaced vent holes, at least four in number, of $\frac{3}{16}$ in. to $\frac{1}{2}$ in. diam. which shall be provided with bushings of bronze or other corrosion resistant metals or shall pass through a liner of such metal. These bushings shall be exactly flush with

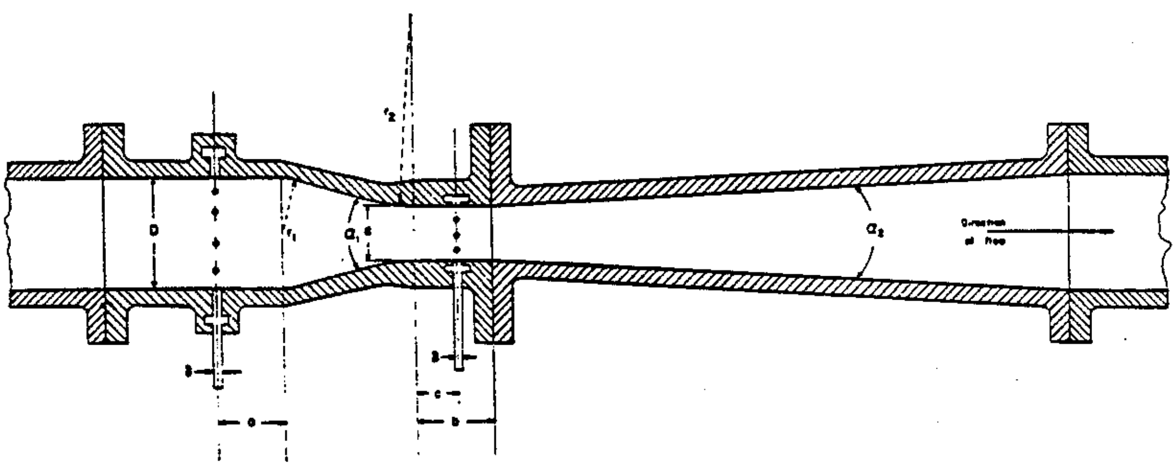


FIG. 12 PROPORTIONS OF HERSCHEL-TYPE VENTURI TUBES RECOMMENDED BY THE TECHNICAL COMMITTEE No. 30 ON MEASUREMENT OF FLUID FLOW OF THE INTERNATIONAL ORGANIZATION FOR STANDARDIZATION

D = Pipe diameter inlet and outlet
d = Throat diameter as required
a = 0.25 D to 0.75 D for 4″ ≦ D ≦ 6″, 0.25 D to 0.50 D for 6″ < D ≦ 32″
b = d
c = $d/2$
δ = $\frac{3}{16}$ in. to $\frac{1}{2}$ in. according to D
Annular pressure chamber with at least 4 piezometer vents
r_2 = 3.5 d to 3.75 d
r_1 = 0 to 1.375 D
α_1 = 21° ± 2°
α_2 = 5° to 15°

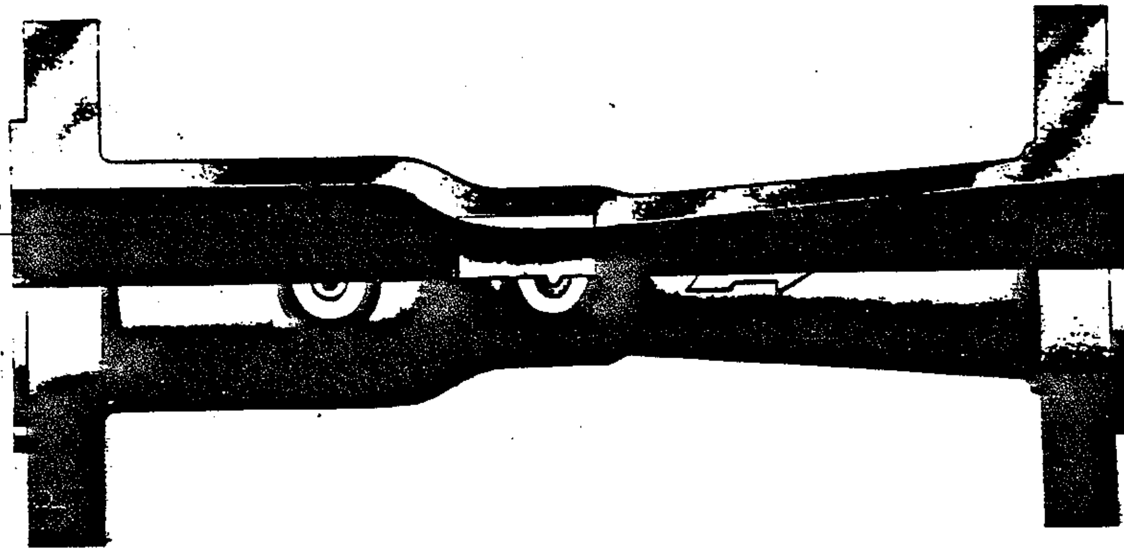


Fig. 13 A Venturi-Nozzle Tube

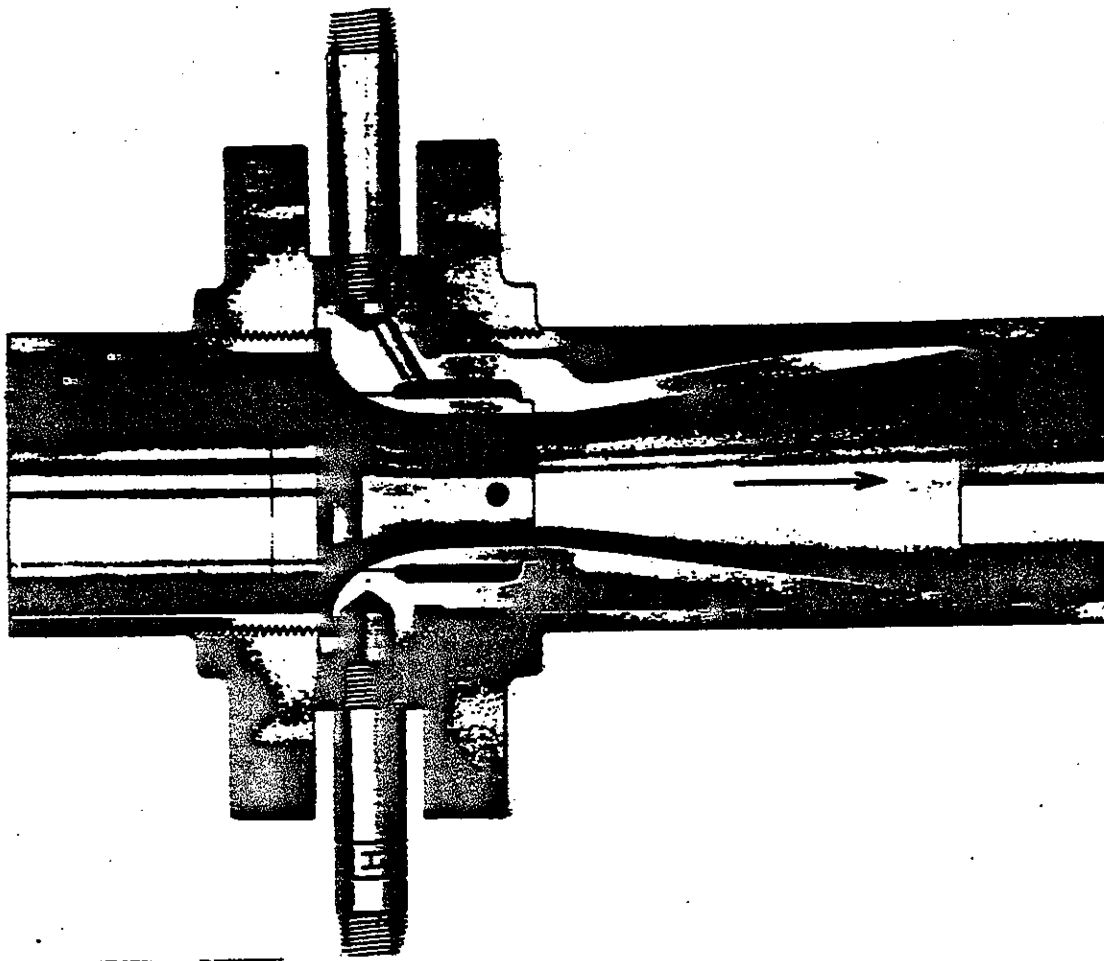


Fig. 14 A Venturi Insert Nozzle

the inside surface of the tube and shall have sharp corners which will readily cut a soft material and will not visibly reflect light. These shall be cylindrical with no waves, bulges or steps of more than 0.00025 in. at the throat or 0.002 in. at the inlet.

(4) The Venturi tube shall be connected to the pipe line by end flanges, or by welding.

(5) Venturi tubes shall be made of cast iron, meehanite, or cast steel for pipe sizes larger than 2 in., with the throat section lined with brass, bronze, or other corrosion resistant alloy and machined to a smooth surface.

For high temperatures, the coefficient of thermal expansion of the throat liner shall be as nearly as possible that of the tube material.

(6) The maximum diameter ratio β shall not exceed 75 per cent nor shall the minimum be less than 40 per cent.

(*b*) *Special Forms.* Special forms of Venturi tubes may be used. One such type commonly used in the measurement of high-pressure feedwater and similar applications, is the Venturi-nozzle tube shown in Fig. 13. Another special form is the Venturi insert nozzle shown in Fig. 14.

32 Coefficient of Discharge.

(*a*) *For Standard Form Tubes.* Unless the tube has been individually calibrated, the coefficient of discharge shall be obtained from Fig. 15. The curve applies for tubes of from 2 to 32 in. pipe size and diameter ratios between 0.30 and 0.75. When the pipe Reynolds number is larger than 200,000, the coefficient of discharge is constant and equal to 0.984.

(*b*) *For Special Form Tubes.* All special forms shall be calibrated at a recognized laboratory before the test.

33 Pressure Loss. The pressure loss produced by a Venturi tube of the Herschel type may be estimated from the curves in Fig. 5. For special forms of Venturi tubes, there are no pressure loss data available.

(*Continued on page 41*)

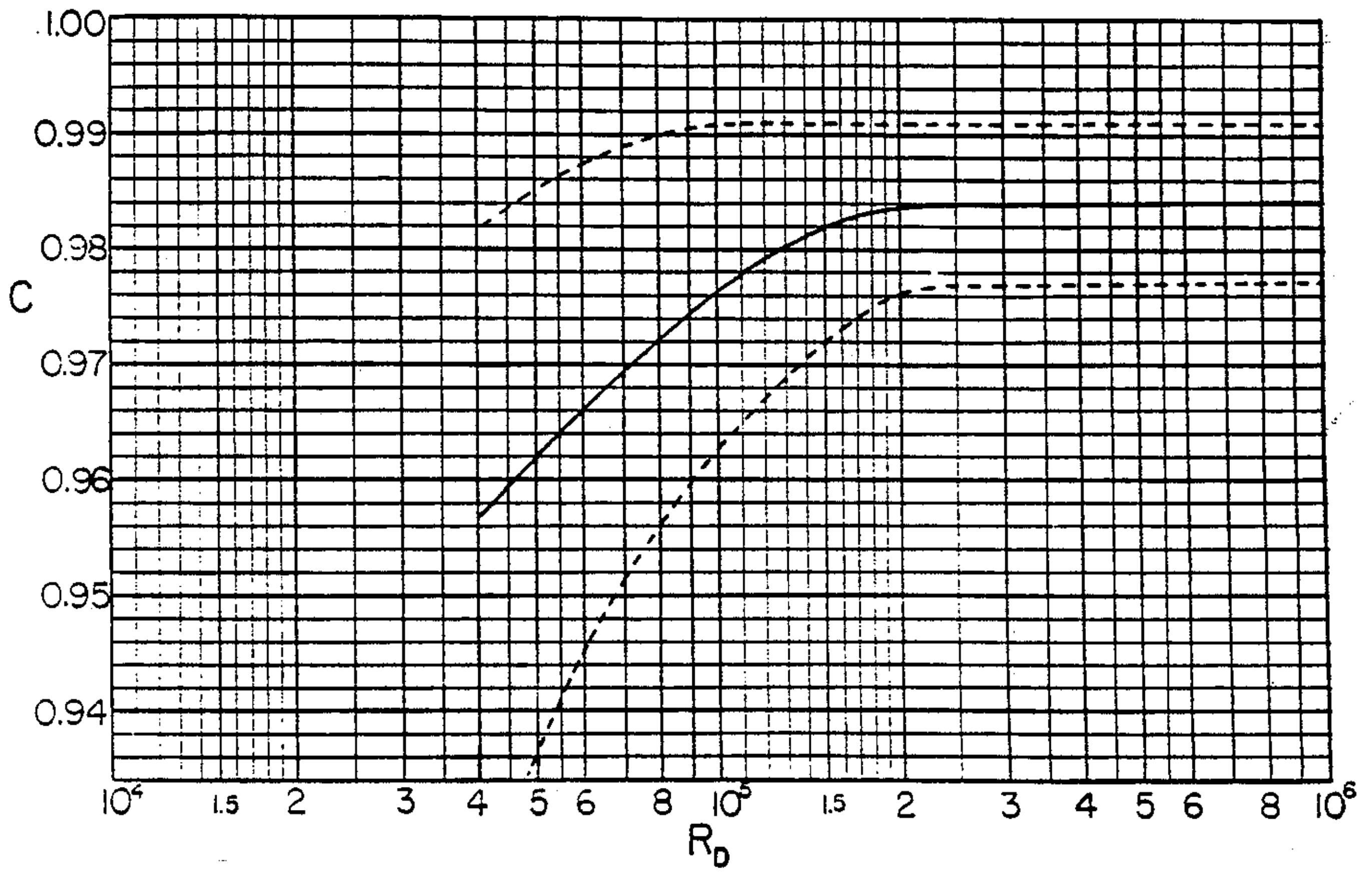
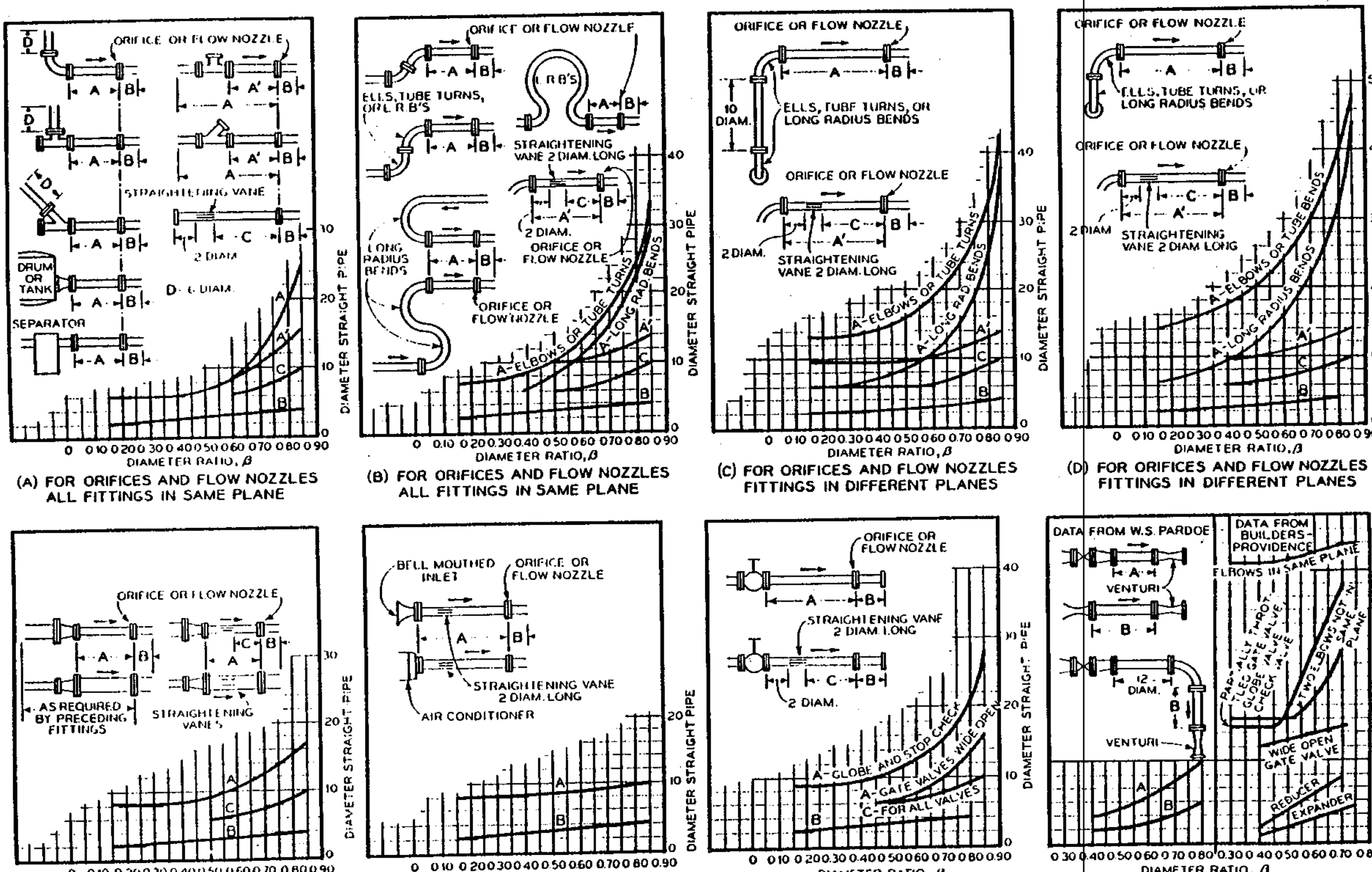


FIG. 15 DISCHARGE COEFFICIENTS FOR HERSCHEL-TYPE VENTURI TUBES AS A FUNCTION OF THE PIPE REYNOLDS NUMBER. APPLICABLE TO VALUES OF β FROM 0.25 TO 0.75 IN PIPES OF 2 IN. AND LARGER

(Velocity of approach factor *not* included)

(The tolerance limits are shown by dotted lines. Coefficients shown by this curve should not be used if a direct calibration can be made.)



(A) FOR ORIFICES AND FLOW NOZZLES ALL FITTINGS IN SAME PLANE

(B) FOR ORIFICES AND FLOW NOZZLES ALL FITTINGS IN SAME PLANE

(C) FOR ORIFICES AND FLOW NOZZLES FITTINGS IN DIFFERENT PLANES

(D) FOR ORIFICES AND FLOW NOZZLES FITTINGS IN DIFFERENT PLANES

(E) FOR ORIFICES AND FLOW NOZZLES WITH REDUCERS AND EXPANDERS

(F) FOR ORIFICES AND FLOW NOZZLES IN ATMOSPHERIC INTAKE

(G) VALVES

(H) FOR VENTURI TUBES

NOTE 1: ALL CONTROL VALVES MUST BE INSTALLED ON *OUTLET* SIDE OF PRIMARY ELEMENT

NOTE 2: IN DIAGRAM H THE DISTANCES SHOWN ARE DOUBLE THOSE AT WHICH THERE SEEMED TO BE NO EFFECT

Fig. 16 Piping Requirements for Orifices, Flow Nozzles and Venturi Tubes

(*Continued from page 19*)

SECTION 4, SECONDARY ELEMENTS

34 For Measuring Differential Pressure. The measurements of the differential pressure produced by the orifice, flow nozzle or Venturi tube shall be accomplished by a system which includes any of the following: a differential manometer, a differential recorder, or an indicator, or any combination thereof.

35 Differential Manometer.

(*a*) The differential manometer shall conform to the requirements of the Power Test Code Supplement on Instruments and Apparatus (hereinafter referred to as I & A), Part 2, Chapter 5. To avoid errors due to meniscus effect, it is recommended that the bore of the manometer tubing be as large as possible and no less than ½ in.

(*b*) Note that vertical manometers shall not be used for differential pressures less than 5 in. of manometric fluid. For lower differentials, either an inclined manometer or a micromanometer shall be employed.

(*c*) Before and after each run the differential manometer shall show a zero reading within ¼ per cent of the minimum differential read during that run.

36 Differential Recorder or Indicator. An instrument recording or indicating the differential pressure, or a flow meter recording or indicating directly in terms of the actual flow, may be used. In any case the instrument shall be calibrated carefully before and after the test by impressing known water differential heads on it. The precision of measurement of these water heads shall be to the nearest 0.25 per cent. Such calibrations shall demonstrate the accuracy of the instrument to be within ± 1 per cent of the correct differential head through the range of flow to be tested.

37 For Measuring Inlet Pressure.

(*a*) To establish the specific weight (or density) of a compressible fluid it is necessary among other things to measure the pressure at the inlet of the primary element.

(*b*) Pressures below 25 psig (approximately 60 in. Hg) shall be measured with a liquid filled manometer, which shall conform to the specifications given in I & A, Part 2, Chapter 5. For higher pressures one of the gages specified in I & A, Part 2, Chapter 4, shall be used.

(*c*) Proper correction shall be made to compensate for the fluid column between the pressure source and the pressure measuring gage or instrument.

38 For Measuring Temperature.

(*a*) The temperature of the fluid shall be measured in all cases. This may be made either with a mercury-in-glass thermometer, a resistance thermometer or a thermocouple (see I & A, Part 3, Temperature Measurement).

(*b*) To avoid any disturbance in the flow pattern, the preferred location of thermometers shall be 5 to 10 pipe diam following the primary element. When this is impossible they should be located 10 to 15 pipe diam preceding the primary element. In the case of plenum chambers a thermometer should be placed as close to the primary element as possible, but not in the direct path of flow entering or leaving the element, as shown in Fig. 9.

SECTION 5, INSTALLATION

A, Primary Element

39 The conditions under which orifices, nozzles and Venturi tubes are installed may have more effect on the accuracy of the test than the degree of perfection of manufacture or the characteristics of the devices themselves. The rate of flow computed from the differential pressure produced by these elements may be in error to an unacceptable degree if the piping arrangements are such that distorted flow conditions result. Distortions of velocity traverse, helical swirls, or vortices will all endanger the flow measurement accuracy. A projecting gasket, misalignment, or a burr on a pressure tap can cause considerable error. Therefore the following rules must be followed carefully.

40 Location. When the temperature of the flowing fluid differs materially from the ambient, the primary element preferably should be located in a horizontal line.

41 To insure accurate flow measurement under this supplement it is essential that the fluid enter the primary element with a fully developed turbulent velocity profile, free from swirls or vortices. Such disturbances will be minimized by the use of adequate lengths of straight pipe, both preceding and following the primary element. The *minimum* lengths of such piping are shown in the eight diagrams of Fig. 16. Each diagram shows a somewhat different arrangement of piping. That diagram nearest the actual piping arrangement for the test should be used to determine the required length of straight pipe on both inlet and outlet.

42 If these straight lengths of pipe are not originally available, wherever possible the piping should be rearranged so as to provide these lengths, to secure maximum accuracy of flow measurement.

43 Should any doubt exist as to the correct diagram to use, or if it is impossible to arrange the pipe to obtain the lengths of straight pipe specified in the diagram involved, straightening vanes shall be used. Diagrams (A) through (H), Fig. 16, also specify the minimum length of straight pipe with straightening vanes. The vanes must be preceded by two or more diameters of straight pipe in every case.

44 Cross sections of two recommended types of straightening vanes are shown in Fig. 17. In the tubular type (A) the maximum distance between tube centers shall not exceed $\frac{1}{4}$ the pipe diameter D; and the overall length shall be at least 8 times this dimension. These vanes may be constructed of thin walled tubes welded together. The perforated plate type (B) has plates held 1 pipe diameter apart by spacers; each plate having a large number of small holes. Regardless of the type of straightening vane used, they must be secured firmly in place within the pipe.

45 Other types of straightening vanes may be used but their effectiveness cannot be predicted here.

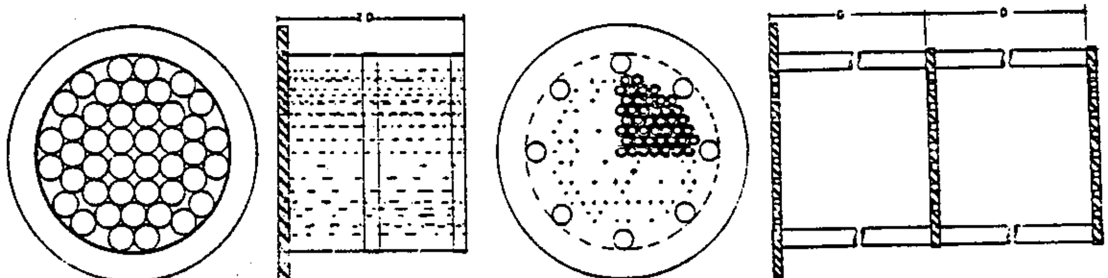
Internal Pipe Surface and Internal Pipe Diameters

46 Whenever possible, the internal diameter of the pipe shall be bored to the diameters and to the tolerances as indicated in Table 7 for a distance of at least four pipe diameters, D, preceding the orifice or nozzle, and for a distance of at least 2 pipe diameters beyond the inlet face of the orifice or nozzle. The bored portions shall be faired into the unbored portion at an included angle of not more than 30 deg.

In case the diameter of the pipe or some other limitation makes boring impossible the pipe shall be round within $\frac{1}{4}$ of 1 per cent of the average pipe diameter, D, and the internal pipe surface shall be straight, free from mill scale, pits or holes, reamer scores or rifling, bumps, or other irregularities.

47 The internal pipe diameter, D, shall be measured at four or more points in the plane of inlet pressure connection p_1, and at four or more points in the plane of the outlet connection p_2. The average of the four or more diameters in the plane of the inlet pressure connection shall be used in calculating the diameter ratio β, of the primary elements.

48 **Venturi Tubes.** The pipe preceding the Venturi tube shall have a commercially smooth finish, free from unusual surface irregularities. The average diameter of the pipe, D, where it joins the Venturi tube shall be within ± 1 per cent of the Venturi tube inlet diameter. Moreover, no single diameter of this inlet pipe section adjacent to the Venturi tube shall differ from the average more than ± 2 per cent. The diameter of the pipe following the Venturi tube will not affect the accuracy of measurement.



A Tubular B Perforated Plates

FIG. 17 TWO RECOMMENDED DESIGNS OF STRAIGHTENING VANES

Installation of the Primary Element

49 **Direction of Flow.** An orifice shall be installed with the sharp edge on the inlet side and the beveled or recess if so provided on the outlet side. A flow nozzle shall be installed so that the elliptical approach section is on the inlet side with the throat on the outlet. A Venturi tube shall be installed so that the short straight section is on the inlet side, with the restoring cone on the outlet.

50 **Centering the Orifice or the Flow Nozzle.** When installed in a pipe line the center of the concentric orifice hole or of the nozzle throat shall be within $\pm \frac{1}{32}$ in. of the axis of the pipe.

strument. For steam service they shall be suitable for saturated steam temperature corresponding to the actual line pressure. For other than steam service they shall be suitable for the actual main line pressure and temperature.

74 If a by-pass valve has not been provided integrally with the instrument, such a valve shall be incorporated between the differential gage shut-off valves and the gage itself, as illustrated in Figs. 29 and 30.

Section 6, Symbols

75 The following symbols have been adopted as conforming in so far as possible with those used by the ASME Research Committee on Fluid Meters and by the American Standards Association.

76 In using numerical subscripts with differential head meters, certain conventions more or less generally used should be stated. The subscript "1" refers to the inlet or upstream section and usually to that particular section at which the inlet pressure is taken. Subscript "2" refers to the outlet or downstream section of pipe at which the outlet pressure is measured in the case of orifices and flow nozzles.

Symbol	Symbol Description	Unit
A	general, area of section; specifically, area of pipe at section of inlet pressure tap	sq in.
a	area of a Venturi throat, nozzle throat or orifice	sq in.
D	general, diameter; specifically, internal diameter of pipe at section of inlet pressure tap	in.
d	diameter of a Venturi throat, nozzle throat or orifice	in.
C	coefficient of discharge	ratio
c_p	specific heat of a fluid at constant pressure	Btu per lb per F
c_v	specific heat of fluid at constant volume	Btu per lb per F
F	velocity of approach factor $= \dfrac{1}{\sqrt{1-\beta^4}} = \dfrac{1}{\sqrt{1-m^2}}$	ratio
F_a	factor to account for the thermal expansion of primary element	ratio
f	function	
G	specific gravity (see Par. 84(c))	ratio
g	acceleration due to gravity (see Note 1)	ft per sec per sec
h_w	effective differential head (see Note 2)	in. of water at 68 F
K	flow coefficient $= CF$	ratio
k	ratio of the specific heats of a gas $= c_p/c_v$	ratio
m	ratio of areas $= a/A = (d/D)^2$	ratio
n	numerical factor to adjust for units of measurement	ratio
p	absolute pressure, the actual or observed (static) pressure (see Note 4)	psia
q	volume rate of flow	cfs
R_D	Reynolds number based on pipe diameter, D	ratio
R_d	Reynolds number based on throat diameter, d	ratio
r	ratio of outlet or throat to inlet static pressure $\dfrac{p_2}{p_1}$	ratio
s	supercompressibility factor, the ratio between the actual specific weight of a gas at conditions p and T and the value computed by Boyle's law	ratio
T	absolute (thermodynamic) temperature	deg R
t	time interval	sec
V	velocity	fps
v	specific volume $(1/\gamma)$	cu ft per lb
w	weight rate of flow, actual	lb per sec
x	ratio of differential pressure to absolute inlet static pressure $\dfrac{p_1 - p_2}{p_1}$	ratio
Y	net expansion factor for square-edged orifices, ratio of the discharge or flow coefficient for a gas to that for a liquid at the same value of R_D or R_d (see Note 5)	ratio

Symbol	Symbol Description	Unit
Y_a	adiabatic expansion factor used with Venturi tubes and flow nozzles	ratio
β (beta)	ratio of throat or orifice diameter to pipe diameter (d/D)	ratio
γ (gamma)	specific weight ($1/v$)	lb per cu ft
μ (mu)	absolute viscosity	lb sec per sq ft
ν (nu)	kinematic viscosity (μ/ρ)	sq ft per sec
π (pi)	3.14159	ratio
ρ (rho)	density	slugs per cu ft

NOTE 1. For most engineering work it is not necessary to distinguish between the exact local value of gravity and the standard value, and it is generally sufficient to use $g = 32.17$ ft per sec per sec. However, when, for precise work, it is desirable to distinguish between the local and standard values, these special symbols may be used: g_L, Local value of acceleration due to gravity, ft per sec per sec; g_o, International standard value of acceleration due to gravity $= 32.1740$ ft per sec sq ($= 980.665$ cm per sec sq).

As an illustration, the curve in Fig. 47 gives the factors for converting inches of mercury and inches of water to local pounds (force) per square inch. In order to have the pounds at standard gravity it would be necessary to multiply the factors by g_L/g_o.

NOTE 2. In connection with differential head meters, the use of h_w to represent the differential pressure in inches of water at 68 F, conforms to the convenience and desires of commercial users. However, in the development of equations of flow it may be desirable to express the head, or differential pressure producing the flow as a column of the flowing fluid, measured in feet. An appropriate symbol for such use would be h.

NOTE 3. As used in this code, V denotes the area average velocity. Hence $V_1 = q/A$, and $V_2 = q/a$. V_s, as used in defining the Mach number, represents the velocity of sound in the fluid concerned under the then existing conditions.

NOTE 4. It is the general practice to express pressures in pounds per square inch (psi), and conforming to this practice the numerical factors associated with the working equations given in this code are based on the use of this unit. However, in the development of these equations, especially where specific volumes and specific weights are involved, the pressure unit to be considered is pounds per *square foot.*

NOTE 5. In the metering of natural gas with orifice meters equipped with flange taps, it is customary to measure the outlet static pressure p_2, and the corresponding expansion factor is designated Y_2. In other fields of flow measurement where p_1 is measured, the corresponding expansion factor is designated by Y or, more specifically, Y_1.

SECTION 7, CALCULATION OF FLOW RATES

A, Incompressible Fluids

77 The flow of any liquid through an orifice, flow nozzle, or Venturi tube is determined by the following equation:

$$w = \frac{CaF_a n\gamma}{\sqrt{1-\beta^4}}\sqrt{2gh} \text{.....lb per sec.....} [1]$$

where

w = rate of flow
n = a numerical factor dependent upon units used

With the units in American practice Equation [1] is written

$$w_h = 359\ CFd^2F_a\sqrt{h_w\gamma} \ldots\ldots [2]$$

where

w_h = weight rate of flow, lb per hr
C = coefficient of discharge
d = diameter of orifice, flow nozzle or Venturi throat, in
β = diameter ratio, d/D
h_w = differential pressure, in H_2O at 68 F
γ = specific weight of the flowing fluid at the inlet side of the primary element, lb per cu ft
F_a = thermal expansion factor

B, Compressible Fluids

78 **Orifices.** To compensate for the change in specific weight as the fluid passes through the orifice Equation [2] must be modified by the expansion factor Y so that

$$w_h = 359\ CFd^2F_aY\sqrt{h_w\gamma} \ldots\ldots [3]$$

or

$$w_h = 359\ \overset{K}{CF}d^2F_aY\sqrt{\frac{h_w}{v_1}} \ldots\ldots [4]$$

where

v_1 = specific volume of the flowing fluid at the inlet side of the primary element, cu ft per lb

79 **Flow Nozzles and Venturi Tubes.** Similarly, for flow nozzles and Venturi tubes, Equation [2] must be modified by the factor Y_a so that

$$w_h = 359\ CFd^2F_aY_a\sqrt{h_w\gamma} \ldots\ldots [5]$$

or

$$w_h = 359\ CFd^2F_aY_a\sqrt{\frac{h_w}{v_1}} \ldots\ldots [6]$$

C. Definitions

80 **Coefficient of Discharge.**

(a) If the orifice has not been individually calibrated, the flow coefficient, K, to be used in conjunction with square-edged concentric orifices, shall be obtained from Tables

82 **The Velocity of Approach Factor, F,** is calculated directly from the known values of β, or it can be read from Figs. 36A and 36B.

83 **The Differential Pressure Head, h_w,** is computed from the readings of the manometer or from the differential pressure recorder. The relation between manometer reading h_m and the h_w is as follows:

$$h_w = \frac{h_m(\gamma_m - \gamma_0)}{62.317} \quad [9]$$

where

h_m = inches of differential or inches of manometer fluid

γ_m = specific weight of manometer fluid, lb per cu ft

γ_0 = specific weight of fluid separating manometric from flowing fluid, lb per cu ft

h_w = differential head, in. of water at 68 F

84 (*a*) **The Specific Weight, γ,** for water for various pressures and temperatures can be obtained from Figs. 31, 32, and 37.

(*b*) The specific weight of liquids other than water can be computed by multiplying the specific weight of water at the operating temperature by the specific gravity of the liquid at that same temperature.

(*c*) The specific weight of dry gas or air may be calculated by

$$\gamma = \frac{\gamma_a G p s}{14.697} \quad [10]$$

where

γ = specific weight of dry gas at actual temperature and pressure

γ_a = specific weight of dry air at actual temperature

p = pressure of dry gas, psia

G = specific gravity of gas compared with dry air at the same pressure and temperature conditions

s = supercompressibility factor

The values of γ_a may be taken from Table 9.

(*d*) If the gas contains water vapor, the specific weight may be determined by

$$\gamma = \frac{\gamma_a G\,(p - p')}{14.697} + \gamma_s S \quad [11]$$

where

p = pressure of mixture (barometer + gage pressure), psia

p' = pressure of saturated vapor at the observed temperature, psia

γ_s = specific weight of water vapor at 100 per cent saturation at the observed temperature, lb per cu ft

S = relative humidity, ratio

85 **Thermal Expansion Factor, F_a.** As a consequence of the thermal expansion of the primary element when the measured fluid is hot, a thermal expansion factor, F_a, must be included in such measurements. This may be obtained from Fig. 38.

86 **Expansion Factor, Y or Y_a.** When metering liquids with differential head meters, where no appreciable expansion takes place, the values of both Y and Y_a are unity. When metering gases with Venturi tubes and flow nozzles, the expansion which accompanies the change in pressure takes place in an axial direction only, due to the confining walls of these differential producers. The adiabatic expansion factor Y_a compensates for this unidirectional expansion. With the thin plate orifice there are no confining walls and the expansion takes place both radially and axially. To take account of this multidirectional expansion the empirical expansion factor Y is used. Values of Y for square-edged concentric orifices can be obtained from Figs. 39A-B and 40A-B. For eccentric and segmental orifices, values of Y can be obtained from Figs. 41 and 42, respectively. Values of Y_a for flow nozzles and Venturi tubes can be obtained from Figs. 43A-B and 44A-B.

87 **Supercompressibility Factor, s.** In reality, no gas follows either Boyle's or Charles's laws exactly. Different gases depart from these laws by different amounts, and both the amount and direction of departure depend on the temperature. For any given isotherm, this behavior can be represented by writing Boyle's law in the following form

$$\frac{\gamma_2}{\gamma_1} = s\,\frac{p_2}{p_1} \quad [12]$$

in which s is a numerical factor slightly greater or less than 1.00. This excess or deficiency of compressibility over that indicated by Boyle's law has been called the "supercompressibility" of the gas, and the factor s is designated as the "supercompressibility factor."

Values for s for dry carbon dioxide-free air and methane can be obtained from Figs. 45 and 46. For other commercial gases the values of s for the operating temperatures and range of pressures should be determined experimentally. In the case of hydrocarbon fuel gases, tables for determining s are given in the American Gas Association Gas Measurement Committee Report No. 3, 1956. (Note the supercompressibility factors given in the AGA Report No. 3 are actually values of $\sqrt{s}$.)

(*Figs. 36A to 46 on pages 64 to 79; Table 9 on pages 80 and 81*)

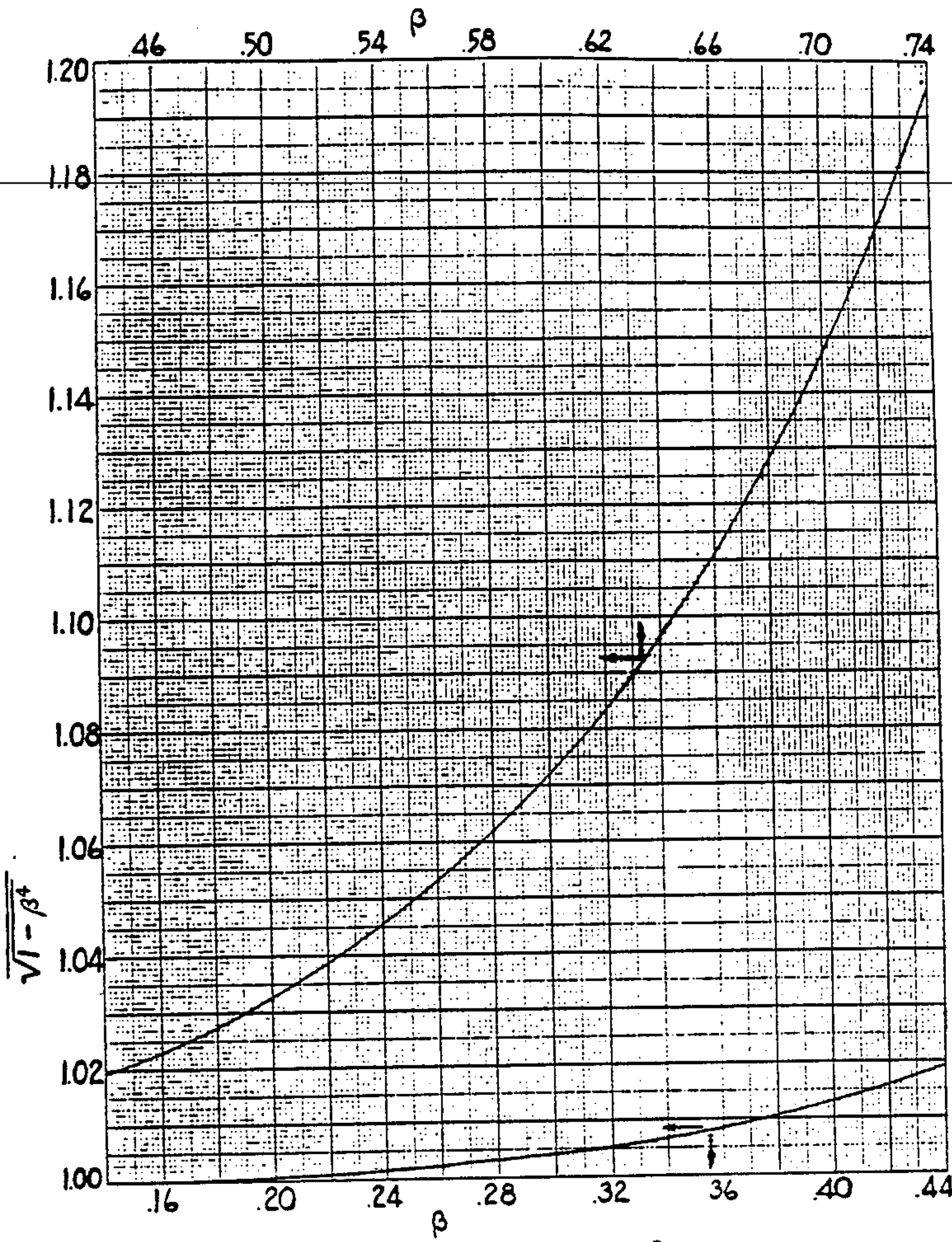


FIG. 36A VALUES OF THE VELOCITY OF APPROACH FACTOR

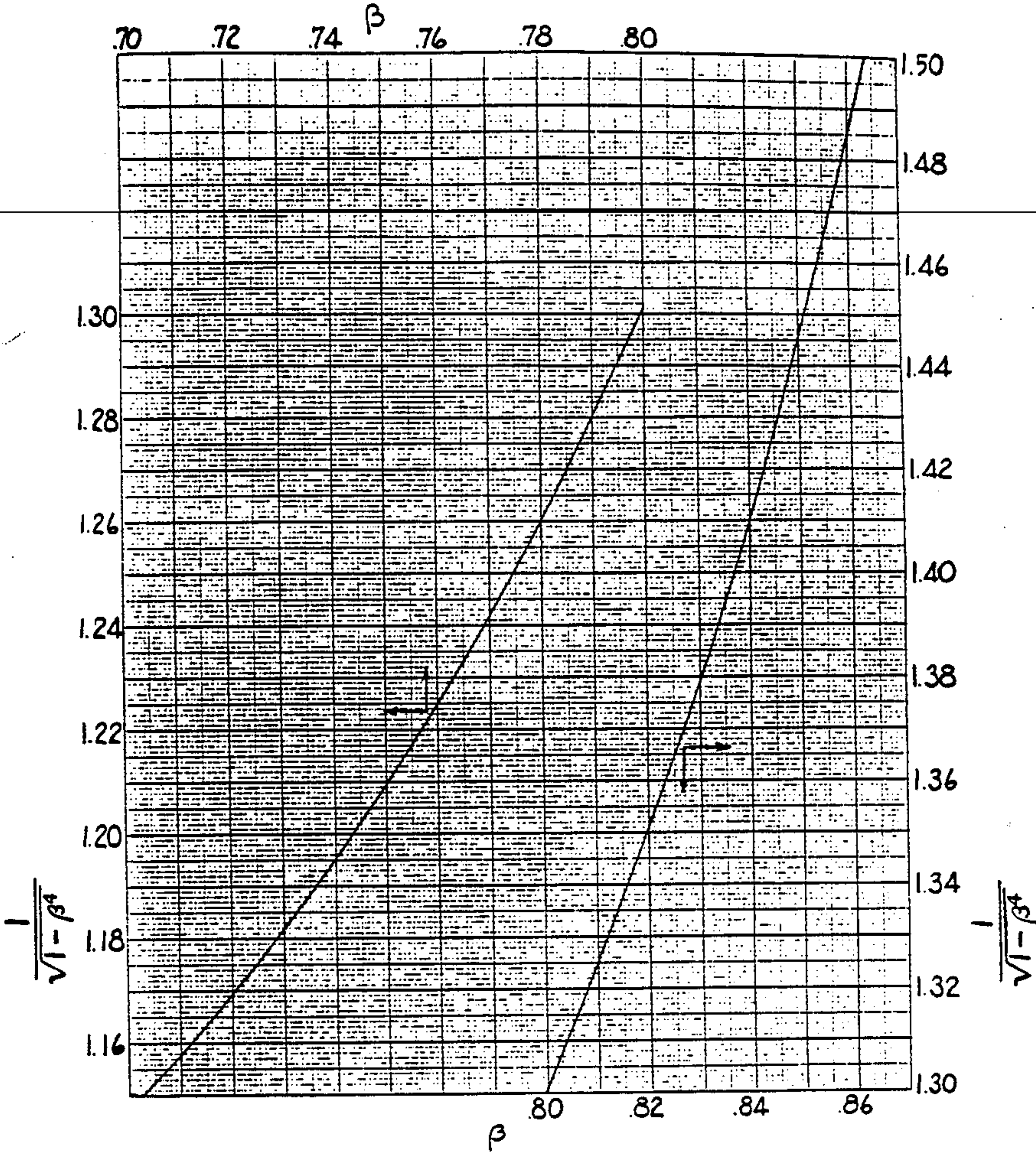


FIG. 56B VALUES OF THE VELOCITY OF APPROACH FACTOR

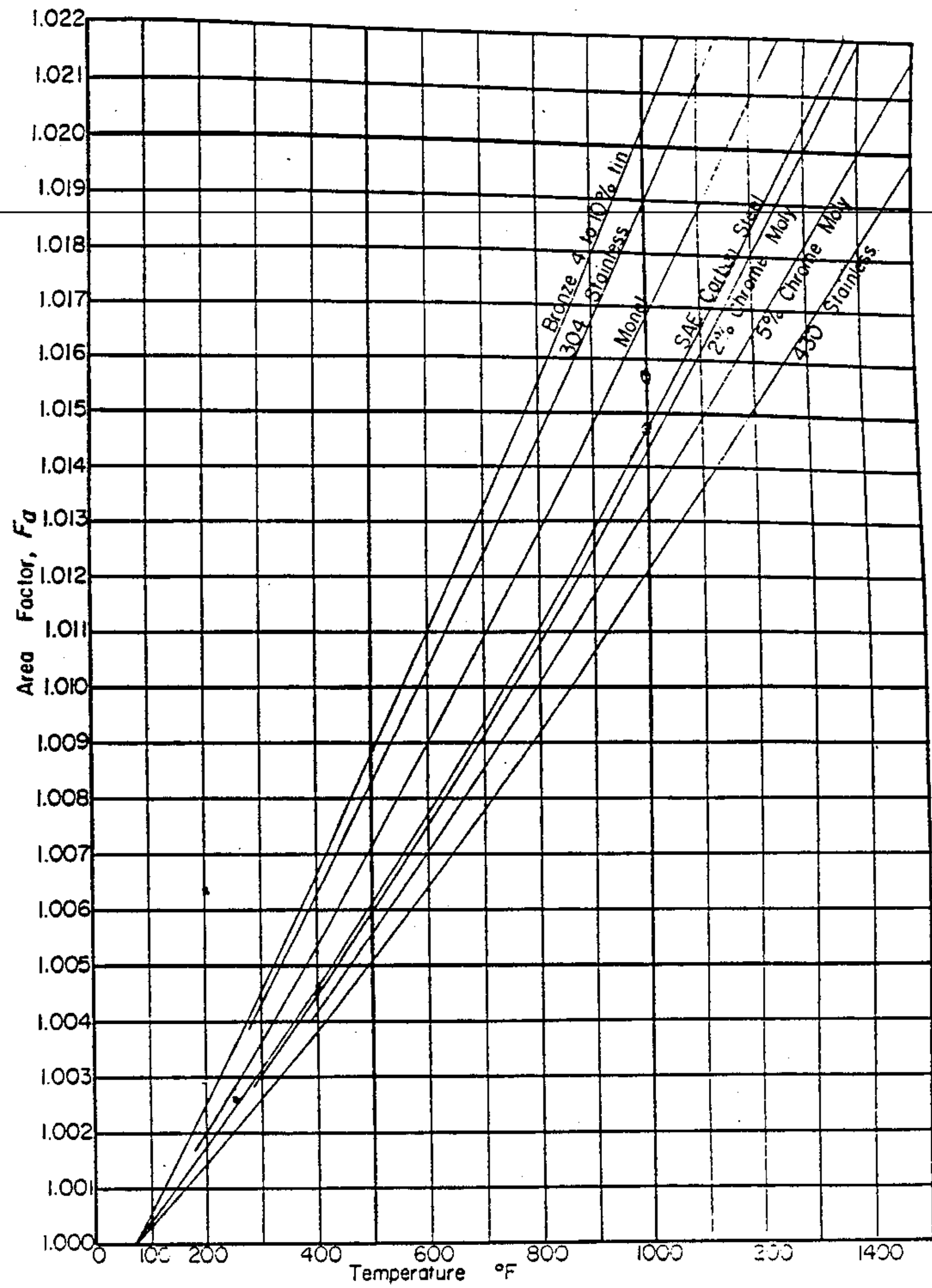
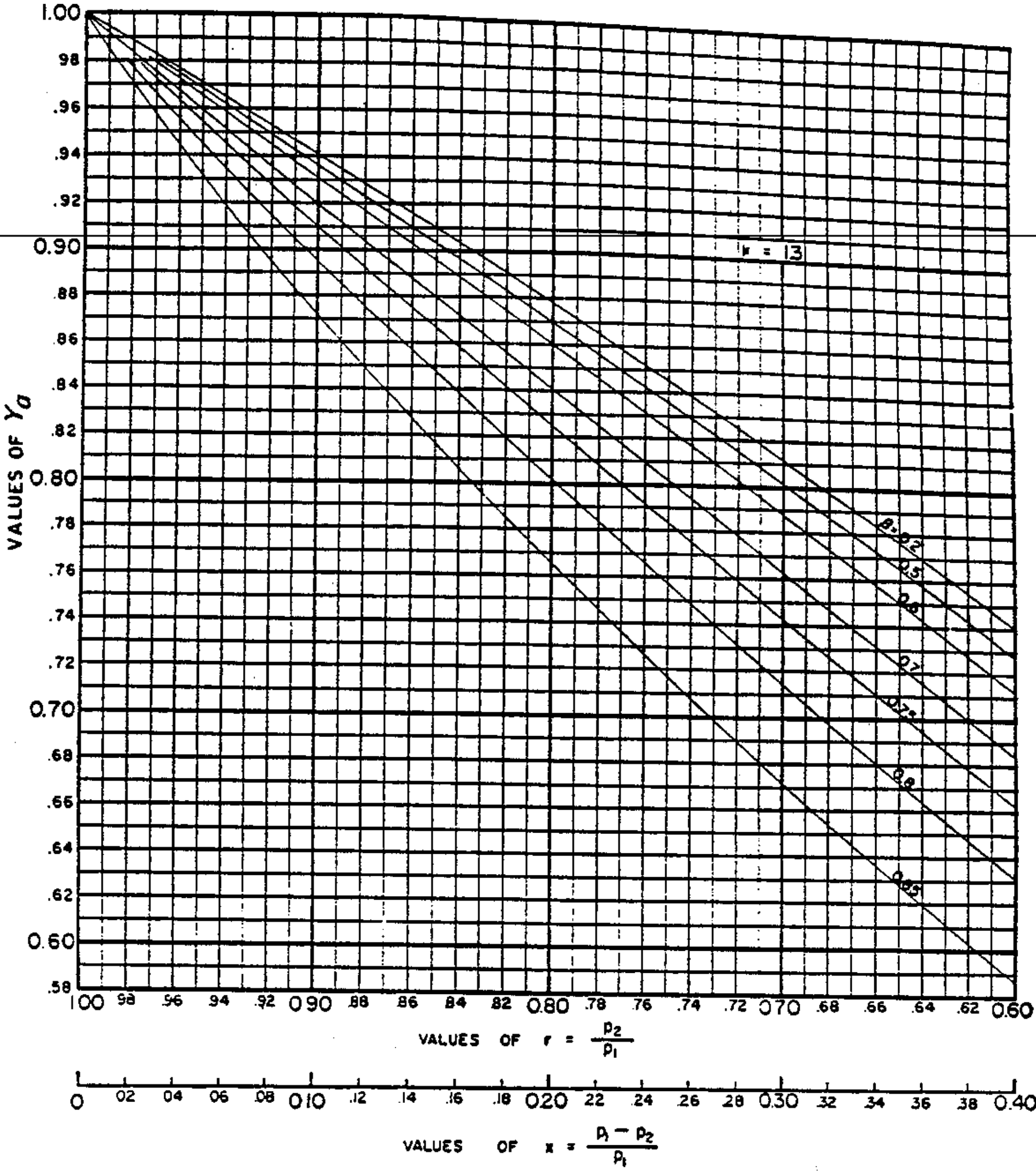


Fig. 38 Area Factors for Thermal Expansion of Primary Elements
(*Note:* The use of bronze in piping is restricted to temperatures below 406 F.)



These curves represent the equation $Y_a = \left[r^{2/k} \left(\frac{k}{k-1} \right) \left(\frac{1 - r^{\frac{k-1}{k}}}{1 - r} \right) \left(\frac{1 - \beta^4}{1 - \beta^4 r^{2/k}} \right) \right]^{1/2}$

Fig. 43A The Adiabatic Expansion Factor, Y_a, for the Metering of Compressible Fluids with Venturi Tubes and Flow Nozzles

(Values of Y_a versus the pressure ratio r, $k = 1.3$)

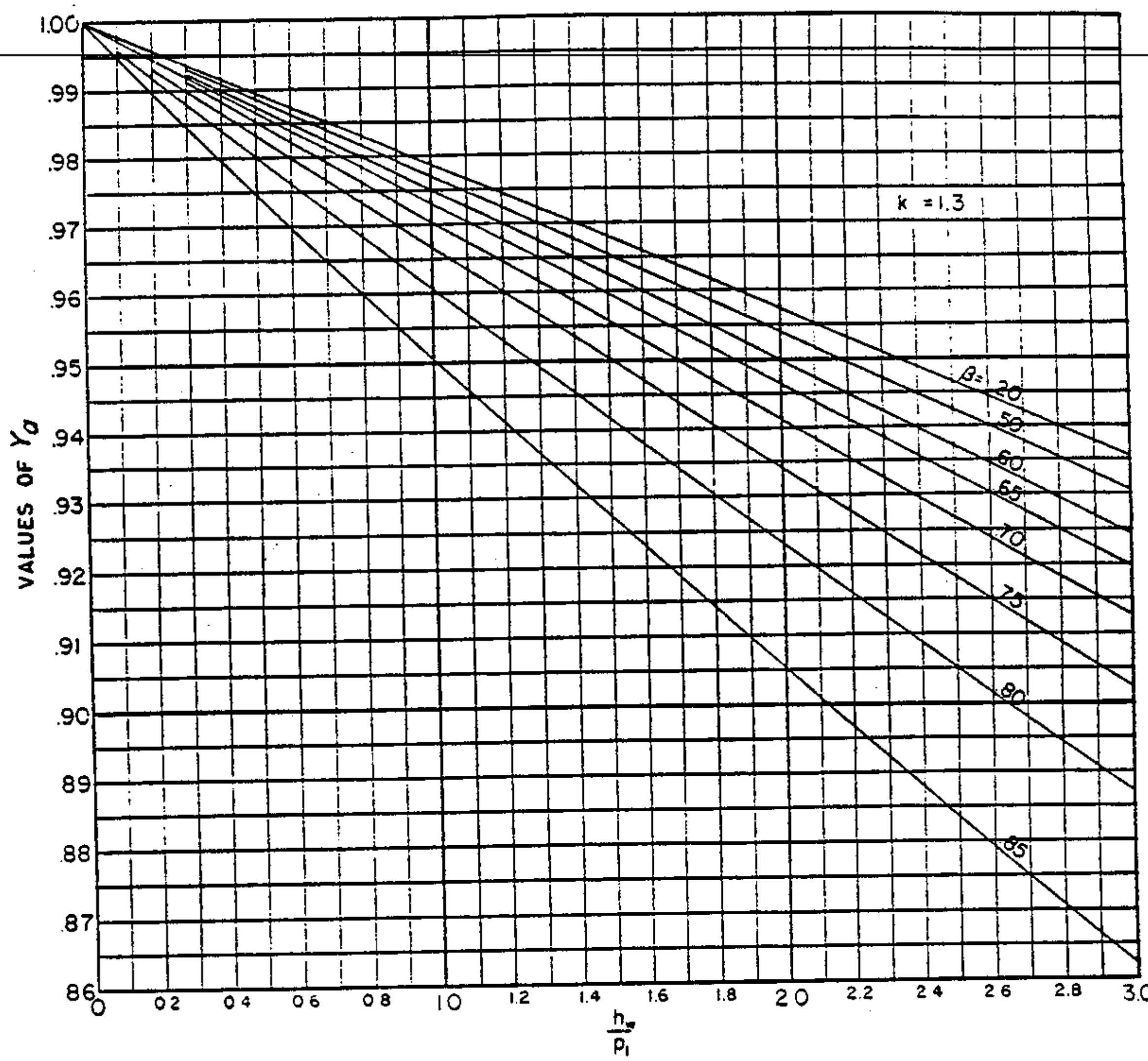
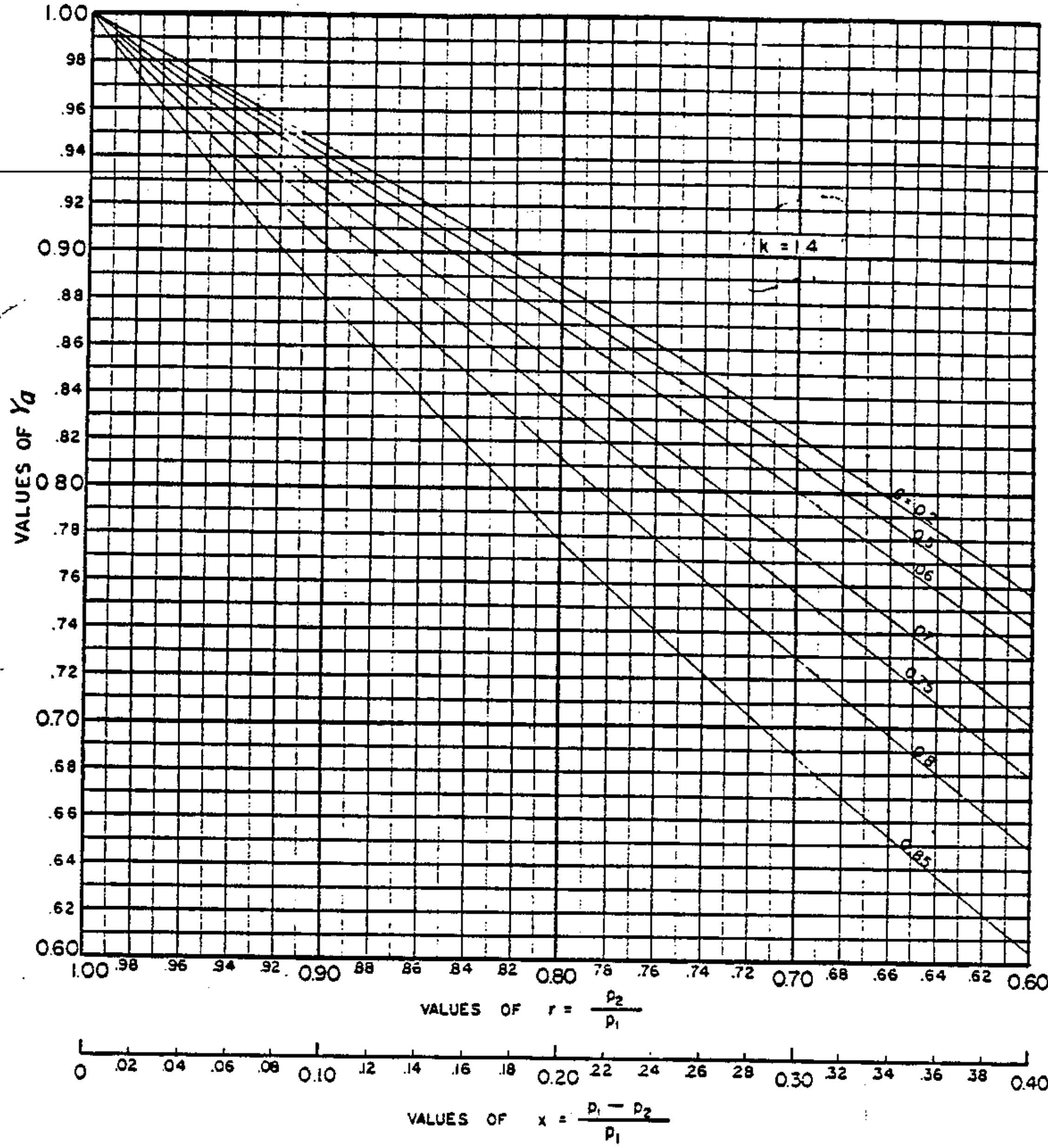


FIG. 43B VALUES OF Y_a FROM FIG. 43A VERSUS VALUES OF h_w/p_1
(h_w in. of water at 68 F, p_1 psia)



These curves represent the equation $Y_a = \left[r^{2/k}\left(\frac{k}{k-1}\right)\left(\frac{1-r^{\frac{k-1}{k}}}{1-r}\right)\left(\frac{1-\beta^4}{1-\beta^4 r^{2/k}}\right)\right]^{1/2}$

FIG. 44A THE ADIABATIC EXPANSION FACTOR, Y_a, FOR THE METERING OF COMPRESSIBLE FLUIDS WITH VENTURI TUBES AND FLOW NOZZLES

(Values of Y_a versus the pressure ratio r, $k = 1.4$)

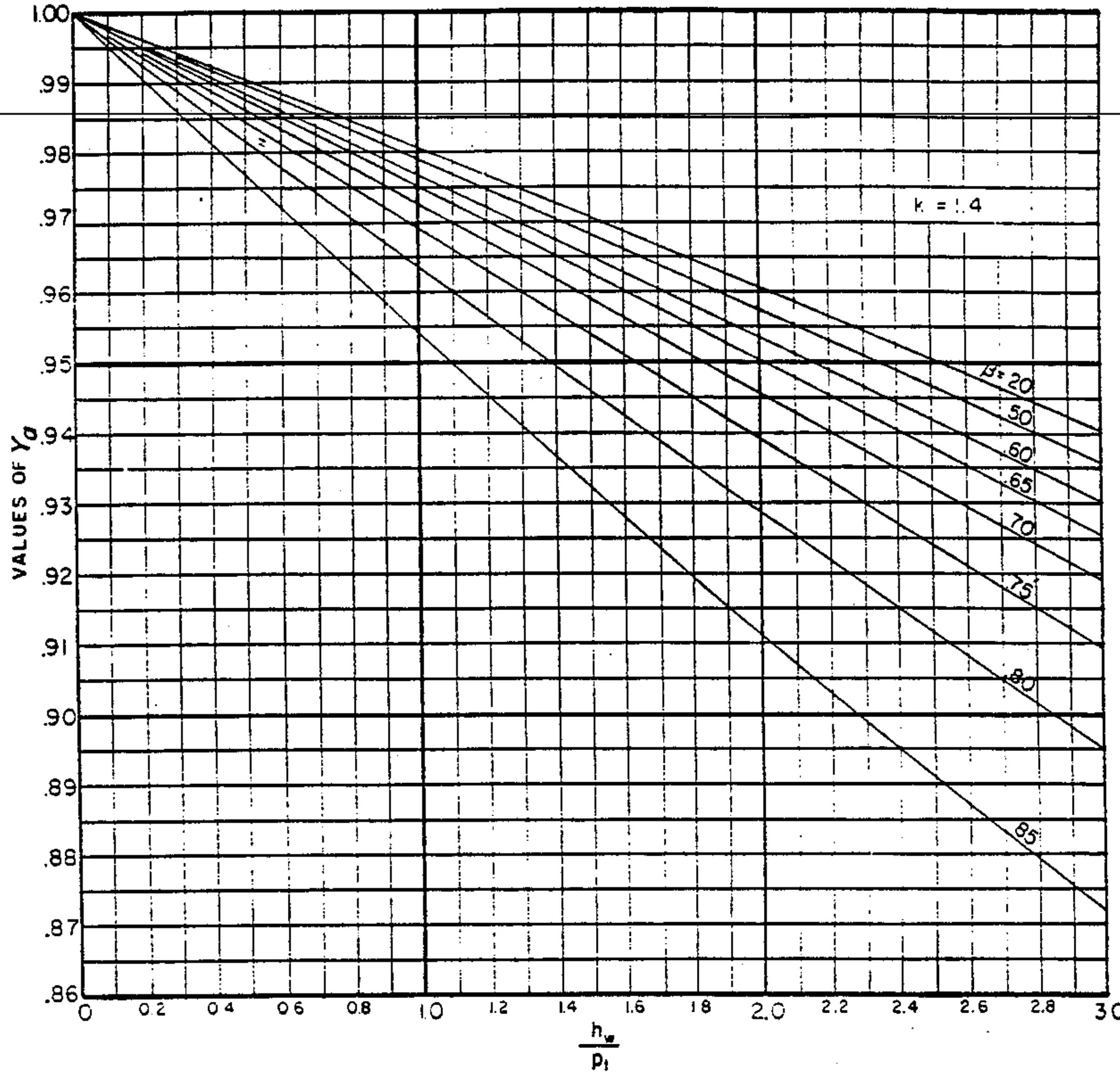


FIG. 44B VALUES OF Y_a FROM FIG. 44A VERSUS VALUES OF h_w/p_1

(h_w in. of water at 68 F, p_1 psia)

4.2 MAJOR EQUIPMENT

Table 4.2-1
Listing of Major Equipment in Area 200

Area	Description	Equipment No.
200	Reactor train A isolation damper	DMP-201A
200	Reactor train B isolation damper	DMP-201B
200	Reactor train C isolation damper	DMP-201C
200	Reactor train D isolation damper	DMP-201D
200	Reactor train E isolation damper	DMP-201E
200	Reactor train F isolation damper	DMP-201F
200	Reactor train G isolation damper	DMP-201G
200	Reactor train H isolation damper	DMP-201H
200	Reactor train J isolation damper	DMP-201J
200	Reactor train A flue gas heater	HTR-201A
200	Reactor train B flue gas heater	HTR-201B
200	Reactor train C flue gas heater	HTR-201C
200	Reactor train D flue gas heater	HTR-201D
200	Reactor train E flue gas heater	HTR-201E
200	Reactor train F flue gas heater	HTR-201F
200	Reactor train G flue gas heater	HTR-201G
200	Reactor train H flue gas heater	HTR-201H
200	Reactor train J flue gas heater	HTR-201J
200	Reactor train A venturi	FE-201A
200	Reactor train B venturi	FE-201B
200	Reactor train C venturi	FE-201C
200	Reactor train D venturi	FE-201D
200	Reactor train E venturi	FE-201E
200	Reactor train F venturi	FE-201F
200	Reactor train G venturi	FE-201G
200	Reactor train H venturi	FE-201H
200	Reactor train J venturi	FE-201J
200	Reactor train A air purge damper	DMP-202A
200	Reactor train B air purge damper	DMP-202B
200	Reactor train C air purge damper	DMP-202C
200	Reactor train D air purge damper	DMP-202D
200	Reactor train E air purge damper	DMP-202E
200	Reactor train F air purge damper	DMP-202F
200	Reactor train G air purge damper	DMP-202G
200	Reactor train H air purge damper	DMP-202H
200	Reactor train J air purge damper	DMP-202J
200	Reactor train A inlet damper	DMP-203A
200	Reactor train B inlet damper	DMP-203B
200	Reactor train C inlet damper	DMP-203C
200	Reactor train A inlet bypass damper	DMP-204A
200	Reactor train B inlet bypass damper	DMP-204B
200	Reactor train C inlet bypass damper	DMP-204C

5.0 AREA 300: AMMONIA STORAGE TO REACTORS

Area 300 is from the ammonia storage tanks to reactor injection nozzles, and includes the ammonia injection skid. Refrigeration grade anhydrous ammonia will be stored in one or two 1,200 gal tanks that will be provided by the ammonia vendor. The ammonia storage tanks will be located on the north side of the abandoned demineralizer building. A constant vapor pressure of ammonia gas will be maintained in the top of the storage tank, utilizing an electric heater system to vaporize the liquid ammonia to maintain a constant pressure, nominally 175 psig. Gaseous ammonia flow is fed to an ammonia accumulator tank via a flow control valve that maintains the tank at a pressure of nominally 30 psig. The accumulator tank and flow control valve are electrically heat traced to makeup for any cooling due to expansion of the ammonia. Ammonia from the accumulator tank is manifolded to each of the SCR reactor trains. A flow control valve delivers ammonia to the dilution air line. A single speed fan provides a constant flow of dilution air to a manifold for the ammonia to maintain proper injection into the duct work preceeding the SCR reactors. The air and ammonia are combined and go through an in-line static mixer, providing proper mixing before going to the ammonia injection grid. A schematic of the entire system for Area 300 is shown in the P & ID drawings in Area 900.